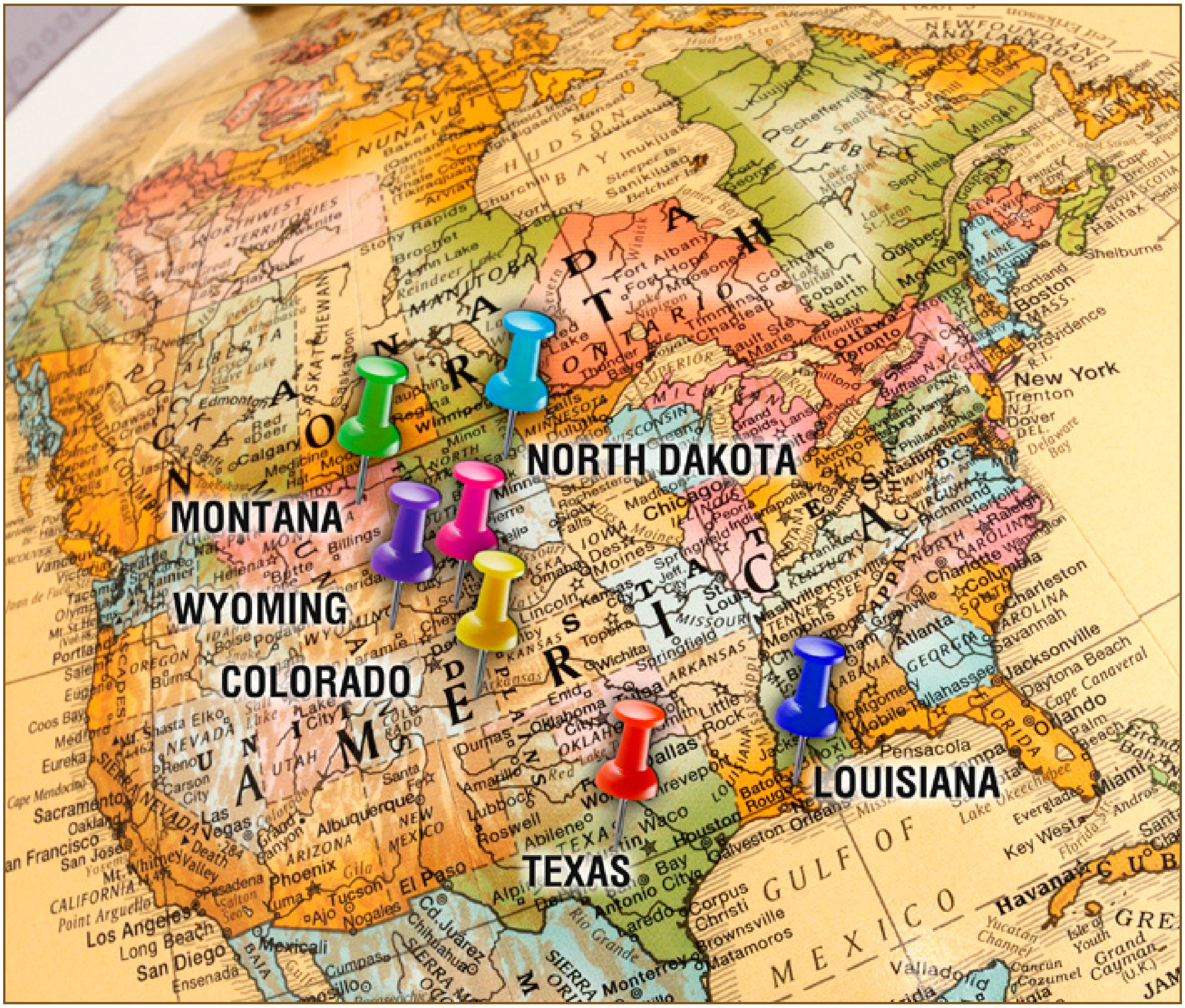
EARTHSTONE
Energy Inc.

2011 ANNUAL REPORT



Earthstone Energy, Inc. is a growth-oriented independent oil and gas exploration and production company focusing on growth and profitability to enhance shareholder wealth. The Company's growth strategy is to pursue exploration and development drilling, acquire interests in strategic and significant producing properties and increase cash flow from existing oil and gas properties.

Going forward we expect to capitalize on our experience in North Dakota, Montana, Wyoming, Colorado, Texas and Louisiana. In these states, our emphasis is on the Williston Basin, the Denver-Julesburg Basin, south Texas and onshore portions of the Gulf Coast.

LETTER TO SHAREHOLDERS

Dear Fellow Shareholders:

We are once again pleased to furnish to you our financial results for our fiscal year ended March 31, 2011. We hope you find this Annual Report informative and are as pleased as we are with our results.

This year our annual meeting will be held in Denver in the third week of September. The weather that time of year is usually very nice and the aspen trees in the mountains outside of Denver are in their finest fall colors. We encourage all of our Shareholders to attend our Annual Meeting and enjoy many of the attractions the city and mountains have to offer.

First, Thank You to all of our Shareholders who supported the Board's recommendations to the two proposals in last year's Proxy Statement; proposals to re-appoint me to the Board and EKS&H as our independent audit firm. It has been an honor to serve as a member of Earthstone's management and Board of Directors.

This Year's Meeting promises to be interesting. At the beginning of this calendar year, we welcomed a new member to our Board of Directors – Andy Calerich, the former President and Chief Financial Officer of American Oil & Gas. Andy brings significant financial and industry experience to our Board and we appreciate his perspectives on our business and look forward to his further guidance and counsel. We ask that you ratify his appointment to our Board through your vote at our annual meeting of Shareholders.

The Board and I request that you also approve the equity incentive compensation plan proposed in this year's Proxy. Competition in the oil and gas industry for talented employees has become fierce. We have recently been out-maneuvered in several key recruitment efforts. We do not currently possess the tools to attract and retain the seasoned, technical employees necessary to respond to our expected growth. To compete in the quest for top-notch employees, recruitment and retention must be a key strength and a competitive advantage. Be assured that neither the Board nor I, as the largest Shareholder, take Shareholder dilution lightly. However, we strongly believe that including an equity component to our compensation package will not only provide a strong recruitment tool, but provide both a positive defense against the recruitment efforts of other companies and strongly align our employees' interests with those of our Shareholders. Therefore, we ask that you approve the 2011 Equity Incentive Compensation Plan through your vote at our annual meeting of Shareholders.

Financial Results and Condition. We achieved a 57% increase in earnings per share (adjusted for the reverse stock split that occurred at the beginning of the calendar year), and are well-positioned to deliver additional Shareholder value in the year ahead. Our fiscal 2010 and 2011 drilling programs, fully funded from internally generated cash, continued to further increase reserves and revenues. Net income rose 56% on a 12% increase in oil and gas revenues compared to the prior fiscal year. We posted solid gains in BOE and PV-10 proved reserves of 17% and 42%, respectively. In fiscal year 2011, the Company invested $3.3 million in exploration and development drilling and the acquisition of wells and leasehold rights. This level of investment more than doubled fiscal 2010 capital expenditures. As we execute on our growth strategy, i.e. we are now involved in more wells and projects, we expect fiscal 2012 capital expenditures to double again.

The Future. Activities in our first quarter suggest that this year will be remarkable. We expect to participate in a record number of wells. Brigham and Zenergy are now actively drilling in the Banks field where we anticipate the addition of fourteen new wells this fiscal year. We also expect to be involved in additional new wells in Indian Hill, Elm Coulee and Mondak fields. While our interest in some of these wells is small, they provide a good rate of return (based on investment) and diversify our risk. Despite the small interests, in the aggregate, they have a meaningful impact on our production, revenue and reserves.

On our two recent acquisitions in Montana – Outlook and Divide – we are currently re-engineering facilities and expect to increase production by this fall. We are adding two new salt water disposal wells for our use, but have engineered them to accept water from outside parties. Plans are also underway to add a third disposal well before winter. As we add infrastructure, we intend to acquire other wells in these areas where the combination of improved economics and emerging Bakken value can be captured.

In addition, we have two new, large projects that we are in the final stages of securing. The first will entail acquiring a small interest in an existing producing well and participating for 10% interest in two new horizontal wells. If successful, we will have the leasehold for six additional wells. On the second project, we expect to have a 15% to 25% interest in a new vertical wildcat well, hopefully, with development wells to follow.

During this exciting and unprecedented time in our industry, we are confident the growth strategy we have implemented will allow us to seize both present and future avenues of expansion. We are focused on developing our horizontal Bakken acreage, while pursuing acquisitions that could substantially enhance our production and reserves. With all of this on the rise – drilling – production – acquisitions – new projects – we believe fiscal 2012 is on track to increase financial performance and Shareholder value.

In Summary. As a Shareholder, I, like you, have a commitment to the success of this enterprise that is stronger than ever. The stability of our core business and the opportunities that surround us promise continued growth for Earthstone. I remain appreciative on a daily basis for the chance to lead this Company and look forward to what the future holds for us.

On behalf of the Board of Directors and employees of Earthstone, we thank all of our Shareholders for your continued and on-going support. I sincerely hope that we can count on your vote on this year's Proxy proposals.

Sincerely,

Ray Singleton

President and Chief Executive Officer,
Chairman of the Board of Directors

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THE COMPANY

Industry

Earthstone Energy, Inc. ("we," "our," "us" or "the Company") is engaged only in the upstream segment of the oil and gas industry, which comprises exploration, production, and development for and of crude oil and natural gas. While we operate a small number of oil wells, we do not own or operate any gas gathering or processing plant facilities nor do we possess sufficient volume on any pipeline to market our product to end users.

Competition

The oil and gas industry is a highly competitive and speculative business. We encounter strong competition from major and independent oil companies in all phases of our operations. In this arena, we must compete with many companies having financial resources and technical staffs significantly larger than our own. Furthermore, having pursued an acquisition strategy for over a decade, we did not develop an in-house geologic or geophysical infrastructure, as have many of our competitors. Rather than incur the time and expense to develop in-house capability, we chose to enter joint ventures with other companies having such resources to accelerate our efforts. Competition is intense with respect to acquisitions and the purchase of large producing properties. Due to the limited capital resources available to us, we have historically focused on smaller and/or marginal properties with behind-pipe potential in our acquisition efforts. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Impact of Inflation and Pricing

We deal primarily in U.S. dollars. Inflation has not had a material impact on the Company in recent years because of the relatively low rates of inflation in the United States. However, the oil and natural gas industry can be cyclical and the demand for production places pressure on the economic stability and pricing within the industry. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, cost declines are likely to lag and may not adjust downward in proportion to declining prices. Changes in prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel. While we do not presently expect business costs to materially rise, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Markets

We are a small company and, as such, have no impact on the market for our product and little control over the price received. Markets for crude oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including other sources of production, competitive fuels and proximity and capacity of pipelines or other means of transportation, seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. Substantially all of our natural gas production is sold at prevailing wellhead gas prices, subject to additional charges customary to an area.

The oil and gas business is not generally seasonal in nature, although unusual weather extremes for extended periods may increase or decrease demand for oil and natural gas products temporarily. Additionally, catastrophic events, such as hurricanes or other supply disruptions, may also temporarily increase the demand for oil and gas supplies from areas unaffected by supply disruptions. Such events and their impacts on oil and gas commodity prices may cause fluctuations in quarterly or annual revenue and earnings. Also, because of the location of many of our properties in Montana and North Dakota, severe weather conditions, especially in the winter months, could have a material adverse effect on our operations and cash flow.

As an oil and natural gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of crude oil and natural gas. Declines in commodity prices will materially and adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of crude oil and natural gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for crude oil and natural gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is to a large extent determined by factors beyond our control.

Our primary objective is to enhance shareholder wealth by increasing our net asset value, net reserves and cash flow through acquisitions, exploration, development, exploitation, and divestiture of oil and gas properties following a balanced risk strategy.

The four key components of our growth strategy are:

- Identification and acquisition of strategic and significant producing properties; strategic and significant in that they are either accretive to our existing production or will provide an increase to the Company's existing production base;
- Utilization of strategic partners with industry experience in the specific geographic areas for which we desire to expand;
- Cost effective implementation of internally and externally generated exploration and development drilling projects; and
- Boosting cash flows from existing oil and natural gas production through a combination of cost control and the exploitation of behind-pipe potential.

Our primary operational focus is in the Montana and North Dakota portions of the Williston basin. This oil rich basin has been, and will continue to be, allocated the majority of our capital expenditure budget. We have been involved in the Williston basin since the early 1980's and only in south Texas does the Company have a longer history. Accordingly, we have a significant understanding of, and exposure to, both the local geology and geologic processes.

The Williston basin and our south Texas waterfloods are primarily oil producing properties. In an effort to expand our reserves and to diversify our portfolio of properties, we have undertaken efforts in other areas, notably, Colorado, Nebraska and onshore portions of the Gulf Coast. Last year, drilling, particularly non-operated drilling projects, comprised the majority of capital expenditures. In the coming year we expect this trend to continue despite our continued emphasis on the acquisition of producing properties. While we expect to drill a considerable number of wells for our size, this effort is primarily to protect expiring leases and maintain our interests under existing acreage holdings.

Historically, we have not placed emphasis on acquiring new, large, non-producing acreage positions. In the coming year, as our existing inventory of acreage is developed, we could see the need to shift capital expenditure dollars into undeveloped acreage.

We will be focusing on keeping our operating costs under control, as we expect rig and vendor service costs to continue to escalate due to high demand. Maintaining a low overhead structure is fundamental to our cost containment. However, over the last year we have expanded and/or restructured our staff; primarily to comply with increased SEC regulation. Since our fiscal year end, we have added additional operational staff, and expect to continue to do so, as we increase our capacity to drill more wells.

We are using and will continue to use the services of independent consultants and contractors to perform various professional services. We believe that this use of third-party service providers enhances our ability to contain general and administrative expenses.

We caution that the expectations iterated in this Annual Report may be altered by subsequent events or other, more attractive opportunities that may present themselves in the future.

Contemplated Activities

We are continually evaluating other drilling and acquisition opportunities for possible participation. The absence of news and/or press releases should not be interpreted as a lack of development or activity. Generally, at any one time, we are engaged in various stages of evaluation in connection with one or more drilling or acquisition opportunities. Unless required by applicable law, our policy is generally to not disclose the specifics of any such opportunity until such time as that transaction is finalized and we have entered into a definitive agreement regarding the same and then, only when such transaction is material to our business. Similarly, we do not speculate on the outcome of such ventures until the drilling, production or other results are available and have been verified by us.

We may alter or vary all or part of these contemplated activities based upon changes in circumstances, including, but not limited to, unforeseen opportunities, inability to negotiate favorable acquisitions, farmouts, joint ventures, or divestitures, commodity prices, lack of cash flow, lack of funding and/or other events which we are not able to anticipate.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

Our primary source of funding is the net cash flow from the sale of our oil and natural gas production. The profitability and cash flow generated by our operations in any particular accounting period will be directly related to: (a) the volume of oil and gas produced and sold, (b) the average realized prices for oil and gas sold, and (c) lifting costs. At the current price of oil, we believe the cash generated from operations, along with existing cash balances, should enable us to meet our existing and normal recurring obligations during the next year and beyond.

Overview of our Capital Structure

We recognize the importance of developing our capital resource base in order to pursue our objectives. However, subsequent to our last public offering in 1980, debt financing has been the sole source of external funding. In addition to our routine production-related costs, general and administrative expenses and, when necessary, debt repayment requirements, we require capital to fund our exploratory and development drilling efforts and the acquisition of additional properties as well as the enhancement of held and newly acquired properties.

We have received numerous inquiries regarding the possibility of funding our efforts through equity contributions or debt instruments. Given strong cash flows, and the relatively modest nature of our current drilling projects, we have thus far declined these overtures. Our primary concern in this area is the dilution of our existing shareholders. However, going forward, given that one of the key components of our growth strategy is to expand our oil and natural gas reserve base through drilling and/or acquisitions, if we were presented with a significant opportunity and available cash and bank debt financing were insufficient, it is possible we would consider alternative forms of additional financing.

Working Capital

As of March 31, 2011, we had a working capital surplus of $4,930,000 (a current ratio of 3.96:1) compared to a working capital surplus as of March 31, 2010 of $5,062,000 (a current ratio of 3.53:1). The increase in current ratio is primarily a result of the timing between payments made for payables, cash received for revenue and joint interest billings and the timing and use of prepaid balances in addition to the use of cash for the acquisition, development and exploration of oil and gas properties.

Cash Flow

Cash provided by operating activities decreased 2% from $2,666,000 for the year ended March 31, 2010 to $2,624,000 for the year ended March 31, 2011. This change related primarily to the timing and collection of accounts receivable, the timing and payment of accounts payable and accrued liabilities, and the application of prepaid balances.

Net cash used in investing activities more than doubled from the previous year from $1,641,000 for the year ended March 31, 2010 to $3,356,000 for the year ended March 31, 2011. During the year ended March 31, 2011, expenditures were directed to acquisitions of producing properties, the drilling of new horizontal Bakken wells in the Williston basin, the recompletion of D-J basin wells in Colorado and acquisitions of additional acreage.

Net cash used in financing activities was nearly half of that of the pervious year. During the year ended March 31, 2010, $208,000 was used to purchase treasury shares, while $122,000 was utilized for treasury share acquisition for the year ended March 31, 2011. The Company's share buyback program was adopted in October 2008 and will terminate in October 2011, if not extended before then.

Capital Expenditures

The amounts presented herein are presented on an accrual basis, and as such may not be consistent with the amounts presented on the consolidated statements of cash flows under investing activities for expenditures on oil and gas property, which are presented on a cash basis.

During the year ended March 31, 2011, we spent $2,729,000 on various projects. This compares to $2,156,000 for the year ended March 31, 2010. During the year ended March 31, 2011, capital expenditures were comprised of acquisitions (47%), drilling and completions (46%) and leasehold (7%).

LIQUIDITY AND CAPITAL RESOURCES (CONTINUED)

Areas of Investment

Williston Basin

The Williston basin continues to be our highest area of activity, both in terms of cash flow from existing properties and expenditures for drilling efforts as well as the acquisition of producing properties. Approximately half of capital expenditures during the year ended March 31, 2011, were directed to the Williston basin, where funds were spent on the purchase of producing wells, new wells drilled within the Bakken development area, and additional leasehold acreage. We have several areas within the Williston basin where we expect drilling operations to commence and/or continue in 2011. These areas are the Banks Field in McKenzie County, North Dakota, the Mondak Field in McKenzie County, North Dakota, the Elm Coulee Field in Richland County, Montana, our acreage in the Indian Hill Field in McKenzie County and our acreage in Divide County, North Dakota and Sheridan County, Montana. While not our primary area of focus, we continue to deploy capital in legacy areas beyond the Williston basin to exploit reserve potential on existing properties.

Banks Field — McKenzie County, North Dakota

Earthstone retains a 6.5% working interest in approximately 13,000 gross (845 net) acres in and around the Banks field. Early efforts on this prospect were less than successful. With improvements in hydraulic stimulation technology, this area is now much more attractive. In the last year, two companies, Zenergy and SM Energy, have drilled five wells on the prospect. Two wells are now on production (the Pederson 10-3H and Fossom 15-35H). At March 31, 2011, three wells (Ceynar 29-32H, A. Johnson 12-1H and Berquist 33-28H) had been drilled, but were yet to be completed. Since, A. Johnson 12-1H and Berquist 33-28H began producing. In addition, we anticipate Brigham to drill ten wells on this acreage before calendar year end and we have already executed AFEs authorizing the drilling of six of the possibly ten wells.

Mondak Field — McKenzie County, North Dakota

The Company has an interest in three wells in the Mondak Field. One of these wells was drilled in the year ended March 31, 2011, though not yet on production. Since year-end, this well, the Mondak Federal 24X-12, had an initial production of 937 barrels per day. This acreage is currently developed for one well per spacing unit. However, we anticipate that this acreage will be developed for two wells per spacing unit in the future.

Elm Coulee Field — Richland County, Montana

The Company has an interest in four horizontal Bakken wells in the Elm Coulee Field and several, legacy, vertical wells that hold Bakken acreage. Most areas in the Elm Coulee Field contain two wells per spacing unit. Now that this field is reaching maturity, it is not unreasonable to expect select areas of this field to be developed with three wells per spacing unit. We believe it is likely that this will occur in the coming year.

Indian Hill Field — McKenzie County, North Dakota

The Company holds approximately 960 gross (192 net) acres in the Indian Hill Field. With improving hydraulic stimulation technology, a number of Bakken horizontal wells have been drilled in the area. We anticipate that this acreage will be proposed for horizontal Bakken development in the coming year.

Divide County, North Dakota — Sheridan County, Montana

Recently, several companies have drilled in these two counties in the Bakken Shale, resulting in strong production figures. Also in the third and fourth quarter of this year, we acquired a 26.5% working interest in five producing wells and a 25% interest in a shut-in well in Sheridan County, Montana. By virtue of these acquisitions, in addition to the legacy producing properties in these two counties, along with undeveloped leasehold acreage, the Company has an estimated 15,200 gross (4,000 net) acres which could be evaluated for horizontal Bakken development in the coming years.

LIQUIDITY AND CAPITAL RESOURCES (CONTINUED)

Denver-Julesburg Basin — Weld County, Colorado

Approximately 20% of capital expenditures during the year ended March 31, 2011, were spent on drilling and recompletion in the D-J basin. As of March 31, 2010, we had finished the first and second phase of our project to (1) drill and complete sixteen new down-spaced wells on the Antenna Federal property in Weld County, Colorado and (2) to drill six "edge wells" around this property. All development work on the phase one and two on this 640 acre section has been finalized. During the year ended March 31, 2011, we recompleted nine of the existing Codell wells into the J-Sand formation. Kerr-McGee Oil & Gas Onshore, LP is the operator of this project.

Approximately 30% of capital expenditures during the year ended March 31, 2011, were spent in other areas outside of the Williston and D-J basins, on property improvements and leasehold acreage. These projects were funded entirely with internally generated cash flow.

As of March 31, 2011, we have Authorizations for Expenditure ("AFEs") totaling $588,000 for our share in completion costs of new wells in which we share a working interest. At present cash flow levels, we expect to have sufficient funds available for our share of both the outstanding AFEs and any additional acreage, seismic and/or drilling cost requirements that might arise from our existing opportunities. We may alter or vary all or part of any planned capital expenditures for reasons including, but not limited to changes in circumstances, unforeseen opportunities, the inability to negotiate favorable acquisition, farmout, joint venture or divestiture terms, commodity prices, lack of cash flow, and lack of additional funding.

We are continually evaluating drilling and acquisition opportunities for possible participation. Typically, at any one time, several opportunities are in various stages of evaluation. Our policy is to not disclose the specifics of a project or prospect, nor to speculate on such ventures, until such time as those various opportunities are finalized and undertaken. We caution that the absence of news and/or press releases should not be interpreted as a lack of development or activity.

OIL AND GAS PROPERTY

Producing Oil and Gas Properties

	MARCH 31, 2011			
	GROSS WELLS		NET WELLS	
	OIL	GAS	OIL	GAS
Colorado	—	41	—	13.66
Louisiana	2	—	0.11	—
Montana	21	—	9.12	—
North Dakota	31	2	7.80	0.12
Texas	28	1	24.36	0.13
Wyoming	1	—	0.47	—
Total	**83**	**44**	**41.86**	**13.91**

OIL AND GAS PROPERTY (CONTINUED)

Drilling Activities

	EXPLORATORY AND DEVELOPMENTAL WELLS DRILLED IN YEAR ENDED MARCH 31,					
	2011		2010		2009	
	GROSS	NET	GROSS	NET	GROSS	NET
Exploratory						
Productive						
Oil	—	—	—	—	1	0.01
Gas	—	—	—	—	—	—
Dry holes	—	—	1	0.55	—	—
Total	**—**	**—**	**1**	**0.55**	**1**	**0.01**
Development						
Productive						
Oil	20	5.11	5	0.36	3	0.09
Gas	2	0.17	—	—	9	2.27
Dry holes	—	—	—	—	—	—
Total	**22**	**5.28**	**5**	**0.36**	**12**	**2.36**

Leasehold Acreage

We lease the rights to explore for and produce oil and gas from mineral owners. Leases (quantified in acres) expire after their primary term unless oil or gas production is established. Prior to establishing production, leases are generally considered undeveloped. After production is established, leases are considered developed or “held-by-production.” Our acreage is comprised of developed and undeveloped acreage as follows:

	MARCH 31, 2011			
	DEVELOPED ACREAGE		UNDEVELOPED ACREAGE	
	GROSS	NET	GROSS	NET
Colorado	640	384	—	—
Louisiana	687	51	—	—
Montana	7,051	3,131	11,876	3,078
Nebraska	—	—	84,944	18.470
North Dakota	7,096	2,714	19,900	3,717
Texas	3,080	2,486	—	—
Wyoming	1,555	329	40	1
Total	**20,109**	**9,095**	**116,760**	**25,266**

Divestitures/Abandonments

We sold five wells and plugged eight wells during the year ended March 31, 2011.

Capitalized Costs

	MARCH 31,	
	2011	2010
Proved property	$ 35,379,000	$ 33,915,000
Unproved property	3,112,000	1,555,000
Total capitalized oil and gas property	**$ 38,491,000**	**$ 35,470,000**

RESERVES

As of March 31, 2011, our estimated proved developed oil and natural gas reserves in barrels of oil equivalent ("BOE") was 1,137,000, a 17% increase from the prior year end's estimated proved oil and natural gas reserves of 970,000 BOE. This increase primarily reflects the addition of new wells, along with an increase in the life of existing wells due to an increase in oil and natural gas prices.

Geographically, our reserves are located in three primary areas: the Williston basin in North Dakota and Montana, the D-J basin in Colorado and onshore Gulf Coast. The following table summarizes the estimated proved developed oil and natural gas reserves divided between operated and non-operated properties for these three areas as of March 31, 2011:

	MARCH 31, 2011			
	NET OIL (Bbls)	**NET GAS (Mcf)**	**BOE**	**%**
Williston Basin				
Operated	176,763	75,763	189,390	16.7%
Non-Operated	397,698	221,519	434,618	38.2%
	574,461	**297,282**	**624,008**	**54.9%**
South Texas/Onshore Gulf Coast				
Operated	388,103	—	388,103	34.1%
Non-Operated	—	—	—	—
	388,103	**—**	**388,103**	**34.1%**
D-J Basin				
Operated	16,109	172,353	44,835	4.0%
Non-Operated	35,891	265,358	80,117	7.0%
	52,000	**437,711**	**124,952**	**11.0%**
Total	**1,014,564**	**734,993**	**1,137,063**	**100.0%**

Preparation of Proved Reserves Estimates

Our policies regarding internal controls over the recording of reserve estimates require reserve estimates to be in compliance with SEC rules, regulations and guidance. Oil and natural gas reserves have been estimated as of March 31, 2011, for a significant portion of our properties by the Ryder Scott Company ("Ryder Scott") of Houston, Texas. Ryder Scott estimated reserves for properties located in the states of Colorado, Louisiana, Montana, North Dakota and Texas comprising approximately 91% and 93% of the PV-10 of our oil and gas reserves as of March 31, 2011 and 2010, respectively. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years.

We concluded that it was not cost effective to have Ryder Scott prepare reserve estimates for 24 of our 127 producing properties because of their relatively low values. Instead, reserves for these properties were prepared by in-house personnel and contributed 9% and 7% to our reserves as of March 31, 2011 and 2010, respectively.

All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods used are limited to decline curve analysis which utilized extrapolations of historical production data.

Oil and gas reserves and the estimates of the present value of future net revenues were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this Annual Report.

Selected Financial Information

	YEAR ENDED MARCH 31,			
		2011		2010
Revenue				
Oil	$	6,933,000	$	6,223,000
Gas		1,166,000		996,000
Total revenue [1]		**8,099,000**		**7,219,000**
Total production expense [2]		3,527,000		2,942,000
Gross profit	**$**	**4,572,000**	**$**	**4,277,000**
Depletion expense	$	1,131,000	$	1,185,000
Sales volume				
Oil (Bbls)		93,613		98,865
Gas (Mcfs) [3]		172,386		228,575
Average sales price [4]				
Oil (per Bbl)	$	74.06	$	62.94
Gas (per Mcf)	$	6.76	$	4.36
Average per BOE				
Production expense [3,4]	$	28.83	$	21.48
Gross profit [4]	$	37.37	$	31.23
Depletion expense [4]	$	9.24	$	8.65

[1] Amount does not include water service and disposal revenue. For the year ended March 31, 2011, this revenue amount is net of $107,000 in well service and water disposal revenue, which would otherwise total $8,206,000 in revenue for the year ended March 31, 2011, compared to $50,000 to total $7,269,000 for the year ended March 31, 2010.

[2] Overall lifting cost (oil and gas production expenses and production taxes)

[3] Due to the timing and accuracy of sales information received from a third party operator as described in "Volumes and Prices" below, sales volume amounts may not be indicative of actual production or future performance.

[4] Averages calculated based upon non-rounded figures

Overview

Net income for the year ended March 31, 2011, was $1,602,000 compared to net income of $1,028,000 for the year ended March 31, 2010, a 56% increase. The increase in sales prices, as offset by a decline in sales volumes and increase in production costs, resulted in the increase in net income. While overall production expenses increased as compared to these expenses for the year ended March 31, 2010, general and administrative ("G&A") expense declined when compared to the year ended March 31, 2010.

Revenues

Oil and natural gas sales revenue increased $880,000 (12%) for the year ended March 31, 2011, as compared to the year ended March 31, 2010, primarily due to higher realized oil and gas prices per barrel of oil equivalent ("BOE"), as offset by reduced sales volumes.

RESULTS OF OPERATIONS (CONTINUED)

Volumes and Prices

On an equivalent barrel basis, sales decreased 11% from 136,961 BOE for the year ended March 31, 2010 to 122,344 BOE for the year ended March 31, 2011.

Oil sales volumes decreased 5% from 98,865 barrels for the year ended March 31, 2010 to 93,613 barrels for the year ended March 31, 2011, while the average price per barrel increased 18% from $62.94 for the year ended March 31, 2010 to $74.06 for the year ended March 31, 2011. The decrease in oil volumes was primarily related to production declines on two wells; the Halvorsen 31X-36 in the Williston basin and the USA 4-36 in the D-J basin. These two wells, both newly drilled in 2009, contributed high initial production for the year ended March 31, 2009. As anticipated, during the year ended March 31, 2011, these two wells exhibited steep, but normal initial declines; thereby reducing oil sales by approximately 4,731 barrels from the year ended March 31, 2010.

To a lesser extent, for the reasons detailed in the paragraph below, oil volumes in the D-J basin reported for the year ended March 31, 2010 were not representative of normal oil sales. Oil sales from these wells were approximately 1,200 barrels higher than actual volumes sold in the period.

Natural gas sales volumes decreased 24% from 228,575 Mcf for the year ended March 31, 2010 to 172,386 Mcf for the year ended March 31, 2011, while the average price per Mcf increased 55%, from $4.36 for the year ended March 31, 2010 to $6.76 for the year ended March 31, 2011. This apparent decline in gas sales volume was attributable to the reporting for the year ended March 31, 2010 a portion of gas volumes for the year ended March 31, 2009 due to inaccurate estimates at the close of the year ended March 31, 2009. In March 2010, we received and reported for the year ended March 31, 2010, gas sales that exceeded our previous accrued estimates of gas sales from periods back to April 2008. From April 2008 to September 2009, the operator of our D-J basin wells was in the midst of an accounting system conversion and furnished us with minimal data. In those prior periods, we estimated and accrued gas sales based on the information available at the time. Had accurate information on gas sales been available and reported in those prior periods, our reported gas sales volumes for the year ended March 31, 2010, would have been lower than those reported. Excluding the volumes reported for the year ended March 31, 2010 that pertained to prior periods, gas sales volumes for the two most current years were comparable.

Production Expense

	YEAR ENDED MARCH 31,	
	2011	**2010**
Lease operating costs	$ 1,874,000	$ 1,680,000
Workover costs	856,000	452,000
Production taxes	586,000	498,000
Transportation and other costs	211,000	312,000
Total production expense	**$ 3,527,000**	**$ 2,942,000**

Oil and natural gas production expense increased $585,000 (20%) for the year ended March 31, 2011, as compared to the year ended March 31, 2010. The two principal components of oil and gas production expense are routine lease operating expenses and workovers.

Routine expenses typically include such items as daily well maintenance, utilities, fuel, water disposal and minor surface equipment repairs.

Workovers primarily include downhole repairs and are generally random in nature. Although workovers are expected, they can be much more frequent in some wells than others and their associated costs can be significant. Therefore, workovers account for more dramatic fluctuations in oil and gas expense from period to period. Workover expense increased $404,000 (89%) for the year ended March 31, 2011, as compared to the year ended March 31, 2010. This increase is primarily attributable to operations in the south Texas waterflood fields.

Routine lease operating expense also increased $194,000 (12%) for the year ended March 31, 2011, as compared to the year ended March 31, 2010, which is consistent with the 12% increase in oil and gas revenue.

RESULTS OF OPERATIONS (CONTINUED)

Production taxes, which are also a function of sales revenue, increased $88,000 for the year ended March 31, 2011, as compared to the year ended March 31, 2010. Production taxes as a percent of oil and natural gas sales revenue remained steady at 7%.

The increase in the production expenses was offset by the $101,000 (32%) decrease in transportation costs for the year ended March 31, 2011, as compared to the year ended March 31, 2010, as production was lower for the year ended March 31, 2011. The decline in production resulting in the decrease in transportation costs was nominally offset by such costs increasing for the industry during 2011.

The overall lifting cost (oil and natural gas production expense plus production taxes) per BOE increased 34% from $21.48 for the year ended March 31, 2010 to $28.83 for the year ended March 31, 2011. This increase primarily related to the increase in workover costs as described above. This lifting cost per equivalent barrel is not indicative of all wells, and certain high cost wells could be shut-in should oil prices drop below certain levels.

Other Expenses

Depletion and depreciation expense decreased $56,000 (5%) for the year ended March 31, 2011 as compared to the year ended March 31, 2010 due to the reduction in production. Depletion expense per BOE increased from $8.65 for the year ended March 31, 2010 to $9.24 for the year ended March 31, 2011.

G&A expense decreased $264,000 (15%) for the year ended March 31, 2011, as compared to the year ended March 31, 2010. This decrease was primarily due to reductions in professional fees, which included investor relations costs, legal fees, accounting fees and Sarbanes-Oxley expenses. As a percent of total sales revenue, G&A expense decreased from 24% for the year ended March 31, 2010 to 18% for the year ended March 31, 2011, as a result of greater revenues and cost reductions. G&A expense per BOE decreased 5% from $12.99 for the year ended March 31, 2010 to $12.38 for the year ended March 31, 2011.

Income Tax

For the year ended March 31, 2011, we recorded income tax expense of $206,000. This amount consisted of a current period expense of $104,000, and deferred tax expense of $102,000. Our effective income tax rate decreased from 12.57% for the year ended March 31, 2010 to 11.41% for the year ended March 31, 2011. Our effective income tax rate was lower for the year ended March 31, 2011, primarily due to an increase in deferred tax assets from the amounts originally estimated on the prior year tax provision.

REGULATIONS

The Company is affected by federal, state, regional and local laws and regulations, including, but not limited to, laws governing well spacing, injection into subsurface formations, discharge of materials, pollution cleanup, endangered species, plugging and abandonment of wells, subsequent rehabilitation of well site locations, and other matters involving environmental protection, as well as occupational health and safety, marketing, prices, taxes, allowable rates of production and reporting requirements. Legislation is continually changing and, in general, is becoming more restrictive and may impose restrictions on and/or require the suspension or cessation of operations in affected areas.

We have expended significant funds to comply with laws and regulations in the jurisdictions where we operate, which we expect will require additional capital expenditures and result in an increase in our costs associated with planning, designing, drilling, operating and both installing and abandoning oil and natural gas wells and facilities. Although we are unable to predict what additional legislation, if any, might be proposed or enacted, additional regulatory requirements could impact the economics of our projects. Although environmental requirements do have a substantial impact upon the energy industry, these requirements do not appear to affect us any differently than other companies in this industry who operate in a given geographic area.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Earthstone Energy, Inc.
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Earthstone Energy, Inc. and Subsidiaries (the "Company") as of March 31, 2011 and 2010, and the related statements of operations, shareholders' equity, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Earthstone Energy, Inc. as of March 31, 2011 and 2010, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in the Notes to the financial statements, as of March 31, 2010, the Company has changed its method of determining quantities of oil and gas reserves which impacted the amount recorded for depreciation and depletion and the ceiling test calculation for oil and gas property.

Ehrhardt Keefe Steiner & Hottman PC

Denver, Colorado
June 15, 2011

CONSOLIDATED BALANCE SHEETS

	YEAR ENDED MARCH 31, 2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,051,000	$ 4,905,000
Accounts receivable:		
Oil and gas sales	1,674,000	1,021,000
Joint interest and other receivables, net of allowance of $93,000 and $86,000, respectively	329,000	401,000
Other current assets	539,000	732,000
Total current assets	**6,593,000**	**7,059,000**
Oil and gas property, full cost method:		
Proved property	35,379,000	33,915,000
Unproved property	3,112,000	1,555,000
Accumulated depletion and impairment	(24,713,000)	(23,582,000)
Net oil and gas property	13,778,000	11,888,000
Support equipment and other non-current assets, net of accumulated depreciation of $377,000 and $374,000, respectively	471,000	451,000
Total non-current assets	**14,249,000**	**12,339,000**
Total assets	**20,842,000**	**19,398,000**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	496,000	161,000
Accrued liabilities	1,167,000	1,836,000
Total current liabilities	**1,663,000**	**1,997,000**
Long-term liabilities:		
Deferred tax liability	2,319,000	2,217,000
Asset retirement obligation	1,795,000	1,674,000
Total long-term liabilities	**4,114,000**	**3,891,000**
Total liabilities	**5,777,000**	**5,888,000**
Commitments		
Shareholders' Equity:		
Preferred shares, $0.001 par value, 600,000 authorized and none issued or outstanding	—	—
Common shares, $0.001 par value, 6,400,000 shares authorized and 1,782,000 and 1,773,000 shares issued, respectively	18,000	18,000
Additional paid-in capital	23,020,000	22,945,000
Treasury shares, at cost, 76,000 and 65,000 shares, respectively	(373,000)	(251,000)
Accumulated deficit	(7,600,000)	(9,202,000)
Total shareholders' equity	**15,065,000**	**13,510,000**
Total liabilities and shareholders' equity	**$ 20,842,000**	**$ 19,398,000**

CONSOLIDATED STATEMENTS OF OPERATIONS

	YEAR ENDED MARCH 31,	
	2011	**2010**
Revenues:		
Oil and gas sales	$ 8,099,000	$ 7,219,000
Well service and water disposal revenue	107,000	50,000
Total revenues	**8,206,000**	**7,269,000**
Expenses:		
Oil and gas production	2,941,000	2,444,000
Production tax	586,000	498,000
Well service and water disposal	11,000	43,000
Depletion and depreciation	1,165,000	1,221,000
Accretion of asset retirement obligation	166,000	166,000
General and administrative	1,515,000	1,779,000
Total expenses	**6,384,000**	**6,151,000**
Income from operations	**1,822,000**	**1,118,000**
Other income (expense):		
Interest and other income	12,000	90,000
Interest and other expenses	(26,000)	(32,000)
Total other income (expense)	**(14,000)**	**58,000**
Income before income tax	1,808,000	1,176,000
Current income tax expense	104,000	172,000
Deferred income tax (benefit)	102,000	(24,000)
Total income tax expense	**206,000**	**148,000**
Net income	**$ 1,602,000**	**$ 1,028,000**
Per share amounts:		
Basic	$ 0.94	$ 0.60
Diluted	$ 0.94	$ 0.60
Weighted average common shares outstanding:		
Basic	1,710,453	1,707,353
Diluted	1,710,453	1,707,353

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	COMMON STOCK		ADDITIONAL PAID-IN	TREASURY STOCK		ACCUMULATED	
	SHARES	AMOUNT	CAPITAL	SHARES	AMOUNT	DEFICIT	TOTAL
March 31, 2009	**1,753,000**	**$ 18,000**	**$ 22,825,000**	**(38,000)**	**$ (43,000)**	**$ (10,230,000)**	**$ 12,570,000**
Purchase of treasury shares	—	—	—	(27,000)	(208,000)	—	(208,000)
Share-based compensation	20,000	—	120,000	—	—	—	120,000
Net income	—	—	—	—	—	1,028,000	1,028,000
March 31, 2010	**1,773,000**	**$ 18,000**	**$ 22,945,000**	**(65,000)**	**$ (251,000)**	**$ (9,202,000)**	**$ 13,510,000**
Purchase of treasury shares	—	—	—	(11,000)	(122,000)	—	(122,000)
Share-based compensation	9,000	—	75,000	—	—	—	75,000
Net income	—	—	—	—	—	1,602,000	1,602,000
March 31, 2011	**1,782,000**	**$ 18,000**	**$ 23,020,000**	**(76,000)**	**$ (373,000)**	**$ (7,600,000)**	**$ 15,065,000**

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED MARCH 31, 2011	2010
Cash flows from operating activities:		
Net income	$ 1,602,000	$ 1,028,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and depletion	1,165,000	1,221,000
Deferred tax expense (benefit)	102,000	(24,000)
Accretion of asset retirement obligation	166,000	166,000
Payments on asset retirement obligation	(283,000)	(134,000)
Share-based compensation	75,000	72,000
Change in:		
Accounts receivable, net	(581,000)	419,000
Other current assets	193,000	(224,000)
Accounts payable, accrued and other liabilities	185,000	142,000
Net cash provided by operating activities	**2,624,000**	**2,666,000**
Cash flows from investing activities:		
Oil and gas property	(3,302,000)	(1,612,000)
Support equipment	(54,000)	(29,000)
Net cash used in investing activities	**(3,356,000)**	**(1,641,000)**
Cash flows from financing activities:		
Purchase of treasury shares	(122,000)	(208,000)
Net cash used in financing activities	**(122,000)**	**(208,000)**
Net (decrease) increase in cash and cash equivalents	**(854,000)**	**817,000**
Cash and cash equivalents, beginning of year	**4,905,000**	**4,088,000**
Cash and cash equivalents, end of year	**$ 4,051,000**	**$ 4,905,000**
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ —	$ 17,000
Cash paid for income tax	$ 204,000	$ 7,000
Non-cash:		
Increase in oil and gas property due to asset retirement obligation	$ 265,000	$ 54,000
Vested shares issued as compensation	$ 74,000	$ 48,000
Accrued capital expenditures	$ 141,000	$ 687,000

Summary of Significant Accounting Policies

Organization and Nature of Operations

Earthstone Energy, Inc. was originally organized in July 1969 as Basic Earth Science Systems, Inc. and changed its name in 2010 to Earthstone Energy, Inc. The Company is principally engaged in the acquisition, exploration, development, and production of crude oil and natural gas properties, primarily operating in the Williston basin in North Dakota and Montana, south Texas and the Denver-Julesburg basin in Colorado.

Principles of Consolidation

The consolidated financial statements include the accounts of Earthstone Energy, Inc. and its wholly-owned subsidiary. All significant intercompany accounts and transactions have been eliminated. The Company does not have any unconsolidated special purpose entities.

At the directive of the Securities and Exchange Commission to use "plain English" in public filings, the Company will use such terms as "we," "our," "us" or "the Company" in place of Earthstone Energy, Inc. and its wholly-owned subsidiary. When such terms are used in this manner throughout this Annual Report, they are in reference only to the corporation, Earthstone Energy, Inc. and its subsidiaries, and are not used in reference to the Board of Directors, corporate officers, management, or any individual employee or group of employees.

Basis of Presentation

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP").

Reclassifications

Certain prior year amounts were reclassified to conform to current presentation. Such reclassifications had no effect on the prior year net income, accumulated deficit, net assets or total shareholders' equity.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions concern matters that are inherently uncertain. Estimates and assumptions are revised periodically and the effects of revisions are reflected in the financial statements in the period it is determined to be necessary. Actual results could differ from those estimates.

Fair Value Measurements

Financial instruments and nonfinancial assets and liabilities, whether measured on a recurring or non-recurring basis, are recorded at fair value. A fair value hierarchy, established by the Financial Accounting Standards Board, prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

The Company's financial instruments consist of cash and cash equivalents, trade receivables, trade payables and accrued liabilities, all of which are considered to be representative of their fair market value, due to the short-term and highly liquid nature of these instruments.

The Company incurred asset retirement obligations of $49,000 and $54,000 during the years ended March 31, 2011 and 2010, respectively, the value of which was determined using unobservable pricing inputs (or Level 3 inputs). The Company uses the income valuation technique to estimate the fair value of the obligation using several assumptions and judgments about the ultimate settlement amounts, inflation factors, credit adjusted discount rates, and timing of settlement.

Hedging Activities

We had no hedging activities in the years ended March 31, 2011 and 2010. Hedging strategies, or absence of hedging, may vary or change due to change of circumstances, unforeseen opportunities, inability to fund margin requirements, lending institution requirements and other events which we are not able to anticipate.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Oil and Gas Property

The Company uses the full cost method of accounting for costs related to its oil and gas property. Accordingly, all costs associated with the acquisition, exploration and development of oil and gas reserves (including the costs of unsuccessful efforts) are capitalized. These costs include land acquisition costs, geological and geophysical expense, carrying charges on non-producing properties, costs of drilling, and overhead charges directly related to acquisition and exploration activities. Under the full cost method, no gain or loss is recognized upon the sale or abandonment of oil and gas property unless non-recognition of such gain or loss would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

Capitalized costs are subject to a ceiling test, as prescribed by Securities and Exchange Commission ("SEC") regulations, that limits such pooled costs to the aggregate of the present value of future net cash flows attributable to proved oil and gas reserves, less future cash outflows associated with the asset retirement obligation that have been accrued plus the lower of cost or estimated fair value of unproved properties not being amortized less any associated tax effects. Prices are held constant for the productive life of each well. If the full cost pool of capitalized oil and gas property costs exceeds the ceiling, the excess is reflected as a non-cash charge to earnings. The write-down is permanent and not reversible in future periods, even though higher oil and gas prices in the future may subsequently and significantly increase the ceiling amount. As of the balance sheet date, capitalized costs did not exceed the ceiling test limit.

For the years ended March 31, 2011 and 2010, the oil and natural gas prices used to calculate the full cost ceiling limitation are the 12 month average prices, calculated as the unweighted arithmetic average price of oil and gas on the first day of each month for each of the 12 months prior to the last day of the reporting period (unless prices are defined by contractual arrangements) and net cash flows are discounted at 10 percent.

Prior to March 31, 2010, ceiling calculations were based on the spot price on the last day of the reporting period. This change is a result of SEC requirements for reporting oil and gas activities effective for annual reporting periods ending on or after December 31, 2009. This rule, titled "Modernization of Oil and Gas Reporting" was implemented by the Company effective March 31, 2010. Adoption of this rule impacted depletion expense for the year ended March 31, 2010, as well as the ceiling test calculation for oil and gas properties as of March 31, 2010. The rule further impacted the oil and gas reserve quantities that were estimated by the reservoir engineer. Adoption of this rule for the year ended March 31, 2010 is considered a change in accounting principle inseparable from a change in accounting estimate. The Company does not believe that provisions of this guidance, other than pricing, significantly impacted the financial statements, and it is impracticable to estimate the effect of applying the new rule on net income or the amount recorded for depletion for the year ended March 31, 2010.

Unproved properties are excluded from the ceiling test. Instead, these property costs are periodically reviewed for impairment by reviewing the status of the activity on those properties and surrounding properties either held by us or other parties.

Capitalized costs of oil and gas property, excluding those pertaining to unproved properties, are depleted on a composite units-of-production method based on estimated proved reserves. For depletion purposes, the volume of reserves and production is converted into a common unit of measure at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Depletion expense per equivalent barrel of production was $9.24 and $8.65 for the years ended March 31, 2011 and 2010, respectively.

Oil and Gas Reserves

Oil and gas reserves represent theoretical, estimated quantities of crude oil and natural gas which geological and engineering data estimate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and gas reserves and their values, including many factors beyond the Company's control. Accordingly, reserve estimates are different from the future quantities of oil and gas that are ultimately recovered and the corresponding lifting costs associated with the recovery of these reserves.

Oil and Gas Sales

We derive revenue primarily from the sale of produced natural gas and crude oil. Revenues from production on properties in which the Company shares an economic interest with other owners are recognized on the basis of the Company's interest. Revenues are reported on a gross basis for the amounts received before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded and receivables are accrued using the sales method, which occurs in the month production is delivered to the purchaser, at which time ownership of the oil is transferred to the purchaser.

Payment is generally received between 30 and 90 days after the date of production. Estimates of the amount of production delivered to purchasers and the prices at which it was delivered are necessary at year end. Management's knowledge of the Company's properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices, and other factors are the basis for these estimates. Variances between estimates and the actual amounts received are recorded when payment is received, or when better information is available.

Major Customers and Operating Region

The Company operates exclusively within the United States of America. All of the Company's assets are employed in and all of its revenues are derived from the oil and gas industry. Individual external purchasers of 10% or more of the Company's oil and gas production revenue for the years ended March 31, 2011 and 2010 were as follows:

	YEAR ENDED MARCH 31,	
	2011	**2010**
Valero Energy Corp.	19%	16%
Nexen Marketing USA, Inc.	9%	10%
Total	**28%**	**26%**

For the year ended March 31, 2011 and 2010, approximately 48% and 57%, respectively, of Earthstone's oil and gas revenue was from non-operated properties where the Company has no direct contact with the actual purchaser. On these properties, Earthstone's portion of the product was marketed by the 23 different companies who operate these wells. These 23 companies may, unbeknownst to us, market to one or more of the same purchasers to whom we sell directly. Therefore, we are unable to ascertain the total extent of combined purchaser concentration. To the extent of our knowledge, in the event of the bankruptcy of any one of these purchasers, it has been estimated that the reduction in annual revenue would be less than 10%. It is not expected that the loss of any one of these purchasers would cause a material adverse impact on the Company's results from operations, as alternative markets for oil and gas production are readily available.

Oil and Gas Production Costs

Costs incurred to operate and maintain wells and related equipment and facilities are expensed as incurred. Production costs (also referred to as lifting costs) include the costs of labor to operate the wells and related equipment and facilities, repairs and maintenance, materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities, property taxes and insurance applicable to proved properties and wells and related equipment and facilities, and severance taxes.

Support Equipment

Support equipment (including such items as vehicles, well servicing equipment, and office furniture and equipment) is stated at the lower of cost or market. Depreciation of support equipment is computed using primarily the straight-line method over periods ranging from five to seven years.

Inventory

Inventory, consisting primarily of tubular goods and oil field equipment to be used in future drilling operations or repair operations, is stated at the lower of cost or market, cost being determined by the FIFO method.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Cash and Cash Equivalents

All highly liquid investments with original maturities of ninety days or less are considered to be cash equivalents. During the period and at the balance sheet date, balances of cash and cash equivalents exceeded the federally insured limit.

Asset Retirement Obligation

The Company's activities are subject to various laws and regulations, including legal and contractual obligation to plug, reclaim, remediate, or otherwise restore oil and gas property at the time such asset ceases to be productive. An asset retirement obligation ("ARO") is initially measured at fair value and recorded as a liability with a corresponding asset when incurred if a reasonable estimate of fair value can be made. This is typically when a well is completed or an asset is placed in service. When the ARO is initially recorded, the Company capitalizes the cost by increasing the carrying value of the full cost pool. Over time, the liability increases for the change in its present value (and accretion expense is recorded), while the capitalized cost decreases by way of depletion of the full cost pool. Estimates are reviewed quarterly and adjusted in the period in which new information results in a change of estimate.

Commitments

The Company is committed to a total of $281,000 plus maintenance fees for a five-year lease term ending April 30, 2013 on a 4,000 square foot office space located in downtown Denver, Colorado. The Company does not have any off-balance sheet financing transactions, arrangements or obligations.

Bad Debt Expense

A charge is recognized in general and administrative expenses and an allowance is established against specific receivable balances from joint interest owners in instances where working interest owners dispute amounts billed for their proportionate share in the cost of wells which the Company operates. As individual disputes are resolved, either the expense is reversed in the period of the resolution or the receivable is written down.

Share-Based Compensation

The Company recognizes all equity-based compensation as share-based compensation expense, included in general and administrative expenses, based on the fair value of the compensation measured at the grant date. The expense is recognized over the vesting period of the grant.

Income Tax

Income taxes are computed using the asset and liability method. Accordingly, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities, their respective tax bases as well as the effect of net operating losses, tax credits and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which the differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in income tax rates is recognized in the results of operations in the period that includes the enactment date.

No significant uncertain tax positions were identified as of any date on or before March 31, 2011. The Company's policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of March 31, 2011, the Company has not recognized any interest or penalties related to uncertain tax benefits.

Earnings Per Share

Basic and diluted earnings per share are computed by dividing net income by the weighted average number of common shares outstanding for the period, after giving effect to the 1-for-10 reverse stock split effective December 31, 2010. As of the balance sheet date, no dilutive securities were outstanding.

Subsequent Events

For the year ended March 31, 2011, there were no subsequent events to recognize or disclose in the consolidated financial statements which would either impact the results reflected in this report or the Company's results going forward.

Recent Accounting Pronouncements

In December 2008, the SEC decreed modified instructions for reporting oil and gas activities. The rule, effective and adopted for the Company's year ended March 31, 2010, changes the oil and natural gas prices used to calculate reserve quantities and the full cost ceiling limitation from the spot price on the last day of the reporting period to the 12 month average prices, calculated as the unweighted arithmetic average price of oil and gas on the first day of each month for each of the 12 months prior to the last day of the reporting period (unless prices are defined by contractual arrangements). Adoption of this rule impacted depletion expense for the year ended March 31, 2010, as well as the ceiling test calculation for oil and gas properties as of March 31, 2010. Adoption of this rule for the year ended March 31, 2010 is considered a change in accounting principle inseparable from a change in accounting estimate. The Company does not believe that provisions of this guidance, other than pricing, significantly impacted the financial statements, and it is impracticable to estimate the effect of applying the new rule on net income or the amount recorded for depletion for the year ended March 31, 2010.

In January 2010, the Financial Accounting Standards Board expanded the required disclosure of fair value measurements, requiring disclosure of the amounts and reasons for significant transfers between Level 1 and Level 2 of the fair value hierarchy, and disaggregation in the reconciliation for fair value measurements using significant unobservable inputs to separately provide information about purchases, sales, issuances and settlements. Effective for the Company's year ended March 31, 2010, additional disclosure is also required about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring measurements. Adoption of this amendment, which solely amends disclosure requirements, results in no impact to the Company's financial position, results of operations, or cash flows.

Various other accounting pronouncements have been recently issued, most of which represented technical corrections to the accounting literature or were applicable to specific industries, and are not expected to have a material effect on our financial position, results of operations, or cash flows.

Other Current Assets

Other current assets as of March 31, 2011 and 2010 consisted of the following:

	MARCH 31, 2011	2010
Lease and well equipment inventory	$ 399,000	$ 399,000
Drilling and completion cost prepayments	24,000	244,000
Prepaid insurance premiums	16,000	49,000
Prepaid income tax	81,000	21,000
Other current assets	19,000	19,000
Total other current assets	**$ 539,000**	**$ 732,000**

Lease and well equipment inventory included in other current assets represents well-site production equipment owned by us that has been removed from wells that we operate. This occurs when we plug a well or replace defective, damaged or suspect equipment on a producing well. In this case, salvaged equipment is valued at prevailing market prices, removed from the full cost pool and made available for sale. This equipment is carried on the balance sheet at a value not to exceed the original carrying value established at the time it was placed in inventory. This equipment is intended for resale to third parties at current fair market prices. Sale of this equipment is expected to occur in less than one year. This policy does not preclude us from further transferring serviceable equipment to other wells that we operate, on an as-needed basis.

Drilling and completion cost prepayments represent cash expenditures advanced by us to outside operators prior to the commencement of drilling and/or completion operations on a well.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Other Non-Current Assets

Other non-current assets as of March 31, 2011 and 2010 consisted of the following:

	MARCH 31,	
	2011	2010
Support equipment and lease and well equipment inventory	$ 281,000	$ 272,000
Plugging bonds	60,000	60,000
Other non-current assets	130,000	119,000
Total support equipment and other non-current assets	**$ 471,000**	**$ 451,000**

Support equipment represents non-oil and gas property (including such items as vehicles, office furniture and equipment and well servicing equipment) and is stated at the lower of cost or market. Depreciation of support equipment was $34,000 and $36,000 for the years ended March 31, 2011 and 2010, respectively, which was computed using primarily the straight-line method over periods ranging from five to seven years.

Non-current lease and well equipment inventory, unlike the equipment inventory in other current assets that is held for resale, is intended for use on leases that we operate. This equipment inventory represents well-site production equipment that we own that has either been purchased or has been removed from wells that we operate. When placed in inventory, new equipment is valued at cost and salvaged equipment is valued at prevailing market prices. The inventory is carried at the lower of the original carrying value or fair market value.

Plugging bonds represent Certificates of Deposit furnished by us to third parties who supply plugging bonds to federal and state agencies where we operate wells. These funds are classified as restricted.

Accrued Liabilities

Accrued liabilities as of March 31, 2011 and 2010 consisted of the following:

	YEAR ENDED MARCH 31,	
	2011	2010
Revenue and production taxes payable	$ 340,000	$ 348,000
Accrued compensation	223,000	172,000
Accrued operations payable	239,000	820,000
Accrued income tax payable and other	238,000	396,000
Short term asset retirement obligation	127,000	100,000
Total accrued liabilities	**$ 1,167,000**	**$ 1,836,000**

Asset Retirement Obligation

For the purpose of determining the fair value of the asset retirement obligation incurred during the year ended March 31, 2011, the Company assumed an inflation rate of 4%, an estimated average asset life of 23.5 years, and a credit adjusted risk free interest rate of 8.4%.

The following reconciles the value of the asset retirement obligation for the periods presented. This included a short term obligation of $127,000 and $100,000 as of March 31, 2011 and 2010, respectively, which was a component of accrued liabilities on the balance sheet:

	YEAR ENDED MARCH 31, 2011	2010
Asset retirement obligation, beginning of year	$ 1,774,000	$ 1,698,000
Liabilities settled	(283,000)	(134,000)
Liabilities incurred	49,000	54,000
Accretion	166,000	166,000
Revisions to estimates	216,000	(10,000)
Asset retirement obligation, end of year	**1,922,000**	**1,774,000**
Less current portion	**(127,000)**	**(100,000)**
Asset retirement obligation, less current portion	**$ 1,795,000**	**$ 1,674,000**

Commitments

Office rent expense was approximately $113,000 and $107,000 for the years ended March 31, 2011 and 2010, respectively (including building maintenance charges). The Company is committed to a total of $157,000 for the remaining term ending April 30, 2013. The Company also has commitments pertaining to software, phone and copy machine maintenance contracts totaling $84,000, $80,000, and $13,000 for the years ending March 31, 2012, 2013, and 2014, respectively.

Shareholders' Equity

Reverse Stock Split

Effective December 31, 2010, the Board of Directors authorized and effected a 1-for-10 reverse stock split which converted ten (10) shares of the Company's common stock into one (1) share of common stock. The Board of Directors also authorized and effected a 1-for-5 reverse stock split for the number of authorized common shares and preferred shares as follows: (a) the reduction of the number of authorized shares of common shares from the then authorized 32,000,000 shares down to 6,400,000 shares, and (b) the reduction of the number of authorized shares of preferred shares from the then authorized 3,000,000 shares down to 600,000 shares. Both the common and preferred shares maintain a par value of $0.001. All references to the number of common shares, treasury shares, and per share amounts in the accompanying consolidated financial statements reflect the reverse stock split.

Preferred Shares

The Company has 600,000 shares of authorized preferred stock with a par value of $0.001 available for issuance in such series and preferences as determined by the Board of Directors. Since inception, the Company has not issued any preferred shares.

Common Shares

The Company has authorized 6,400,000 shares of common stock with a par value of $0.001. The total issued common stock as of March 31, 2011, was 1,782,000 common shares.

Share-Based Compensation

On March 8, 2007, the Board of Directors adopted a Director Compensation Plan ("the Plan") allotting up to 50,728 shares of the Company's common stock to be issued to independent, non-employee directors. In connection with the Plan, an annual stock grant equal to $36,000 is awarded to each independent director. The number of shares included in each grant is calculated based upon the average closing price of the ten trading days preceding each April 1st anniversary date. Shares are subject to certain restrictions and vesting.

During the year ended March 31, 2011, 9,270 shares of common stock reserved for issuance under the Plan were authorized for issuance. Accordingly, as of March 31, 2011, 20,716 shares of common stock remain available for issuance under the Plan. Grants of shares of restricted stock vest one-third each year over three years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

In accordance with the terms of the Plan, if a director's participation as a member of the Board ceases or is terminated for any reason prior to the date the shares of restricted stock are fully vested, the unvested portion of the restricted stock shall be automatically forfeited and shall revert back to the Company. The aggregate number of restricted stock awards outstanding and subject to vesting at March 31, 2011, for each non-employee director was as follows: Robertson – 8,555 shares; Rodgers – 8,555; and Calerich – 552. In addition, each of the three independent directors was granted 1,867 shares of restricted stock on April 1, 2011, subject to vesting and forfeiture. All restricted shares are considered issued and outstanding shares of the Company's common stock at the grant date and have the same dividend and voting rights as other common stock.

On January 4, 2011, the Board of Directors authorized the Company to increase the Board of Directors to four members in accordance with the Bylaws. On January 6, 2011, Andrew P. Calerich was appointed a seat on the Board of Directors and was granted restricted common stock valued at $9,000, subject to a vesting period similar to other directors, ergo the aforementioned 552 restricted shares. Consistent with the calculation of shares for the annual grant of stock to directors, the number of restricted shares was determined by the average closing share price for the last ten trading days of the quarter ended December 31, 2010. This price, adjusted for the reverse stock split, was $16.30.

A summary of the status of the Company's nonvested shares under the Director Compensation Plan as of March 31, 2011 and 2010 and changes during the years ended on those dates is presented below:

	YEAR ENDED MARCH 31,			
	2011		2010	
	SHARES	WEIGHTED AVERAGE GRANT DATE FAIR VALUE	SHARES	WEIGHTED AVERAGE GRANT DATE FAIR VALUE
Nonvested shares, beginning of year	15,306	$ 144,000	10,244	$ 120,000
Granted	9,270	81,000	8,982	72,000
Vested	(6,914)	(72,000)	(3,920)	(48,000)
Forfeited	—	—	—	—
Nonvested shares, end of year	**17,662**	**$ 153,000**	**15,306**	**$ 144,000**

As of March 31, 2011, there was $80,000 of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted under the Director Compensation Plan. That cost is expected to be recognized over a weighted-average period of 1.02 years.

The Company granted one key employee 624 restricted shares of Company common stock during the year ended March 31, 2010, valued at $5,000. Such shares vest one-third each year over three years, subject to forfeiture.

Share-based compensation expense of $75,000 and $72,000 was recognized during the years ended March 31, 2011 and 2010, respectively, for restricted share grants to independent directors.

Treasury Shares

On October 22, 2008, the Company's Board of Directors authorized a share buyback program for the Company to repurchase up to 50,000 shares of its common stock for a period of up to 18 months. The program does not require the Company to repurchase any specific number of shares, and the Company may terminate the repurchase program at any time. On November 13, 2009, the Board of Directors increased the number of shares authorized for repurchase to 150,000. On February 10, 2010, the Board extended the termination date of the program from April 22, 2010 to October 22, 2011. During the year ended March 31, 2011, 10,997 shares were repurchased under the share buyback program and 109,440 shares remain available for future repurchase. No treasury shares have been retired.

Income Tax

The provision for income taxes for the years ended March 31, 2011 and 2010 is comprised of the following:

	YEAR ENDED MARCH 31,	
	2011	**2010**
Current:		
Federal	$ 93,000	$ 171,000
State	11,000	1,000
Total current income tax expense	**104,000**	**172,000**
Deferred:		
Federal	95,000	(23,000)
State	7,000	(1,000)
Total deferred income tax expense (benefit)	**102,000**	**(24,000)**
Income tax expense	**$ 206,000**	**$ 148,000**

A reconciliation between the income tax provision at the statutory rate on income taxes and the income tax provision for the years ended March 31, 2011 and 2010 follows:

	YEAR ENDED MARCH 31,	
	2011	**2010**
Federal tax at statutory rate	$ 615,000	$ 400,000
State taxes, net of federal benefit	26,000	9,000
Excess percentage depletion	(270,000)	(283,000)
Adjustments to deferred tax assets related to intangible drilling costs	(148,000)	—
Non-deductible permanent items	—	6,000
Other adjustments, net	(17,000)	16,000
Income tax expense	**$ 206,000**	**$ 148,000**
Effective tax rate expressed as a percentage of income before income tax	**11%**	**13%**

The overall effective tax rate expressed as a percentage of book income before income tax for year ended March 31, 2011, as compared to the ended March 31, 2010, was lower due to the Company having an increase in deferred tax assets from the amounts originally estimated on the prior year tax provision.

Net income tax payments were $204,000 and $7,000 for the years ended March 31, 2011 and 2010, respectively.

Net deferred tax assets and liabilities as of March 31, 2011 and 2010 were comprised of:

	YEAR ENDED MARCH 31,	
	2011	**2010**
Deferred tax assets:		
Allowance for doubtful accounts	$ 34,000	$ 31,000
Asset retirement obligation	703,000	647,000
Statutory depletion carry-forward	1,110,000	1,074,000
Gross deferred tax assets	**1,847,000**	**1,752,000**
Other accruals	69,000	47,000
Depreciation, depletion and intangible drilling costs	(4,235,000)	(4,016,000)
Gross deferred tax liabilities	**(4,166,000)**	**(3,969,000)**
Deferred tax assets (liabilities), net	**$ (2,319,000)**	**$ (2,217,000)**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Projections of future income taxes and their timing require significant estimates with respect to future operating results. Accordingly, deferred tax assets and liabilities are continually re-evaluated and numerous estimates are revised over time. As such, deferred taxes may change significantly as more information and data is gathered with respect to such events as changes in commodity prices, their effect on the estimate of oil and gas reserves and the depletion of these long-lived reserves.

The Company is subject to U.S. federal income tax and income tax from multiple state jurisdictions. The tax years remaining subject to examination by tax authorities are the years ended March 31, 2007 through 2010.

Related Party Transactions

The Company maintains a policy permitting officers or directors to assign to the Company or receive assignments from the Company in oil and gas prospects, but only on the same terms and conditions as accepted by independent third parties. This policy also allows officers or directors and the Company to participate together in oil and gas prospects generated by independent third parties, but only on the same terms and conditions as accepted by non-related third parties. In 2010, Ray Singleton, Earthstone's President and Chief Executive Officer, participated in the drilling of the Crown 41-31 in Sheridan County, Montana on the same terms and conditions as other third parties. The well resulted in a dry hole. During the years ended March 31, 2011 and 2010, no other director or officer participated with the Company in any oil and gas transaction.

In prior years, Mr. Singleton has participated with the Company in the acquisition of producing properties on the same terms and conditions as other third parties. As such, Mr. Singleton paid for his proportionate share of the acquisition costs at the time of the acquisition. With respect to his working interest in the four producing wells in which he currently has an ownership, as of March 31, 2011, the Company had an accrued balance due from Mr. Singleton of $11,000 for his share of operating expenses on these wells, which was billed ten days after year end and for which timely payment was subsequently received. As of March 31, 2010, as a result of his share of oil and gas revenue exceeding the amount of his share of operating expenses, the Company had a balance of $10,000 due to Mr. Singleton.

Oil and Gas Property

The aggregate amount of capitalized costs related to oil and gas property and the aggregate amount of related accumulated depletion as of March 31, 2011 and 2010 are as follows:

	MARCH 31, 2011	MARCH 31, 2010
Proved property	$ 35,379,000	$ 33,915,000
Unproved property	3,112,000	1,555,000
Total capitalized oil and gas property	**38,491,000**	**35,470,000**
Accumulated depletion and impairment	(24,713,000)	(23,582,000)
Net capitalized oil and gas property	**$ 13,778,000**	**$ 11,888,000**

The following shows, by category and year incurred, the oil and gas property costs applicable to unproved property that were excluded from the full cost pool depletion computation as of March 31, 2011:

COSTS INCURRED DURING YEAR ENDED	EXPLORATION COSTS	DEVELOPMENT COSTS	ACQUISITION COSTS	TOTAL UNPROVED PROPERTY
March 31, 2011	$ —	$ 1,216,000	$ 756,000	$ 1,972,000
March 31, 2010	1,000	361,000	73,000	435,000
Prior Years	—	—	705,000	705,000
Total	**$ 1,000**	**$ 1,577,000**	**$ 1,534,000**	**$ 3,112,000**

Costs incurred in oil and gas property development, exploration and acquisition activities during the years ended March 31, 2011 and 2010 are summarized as follows:

	FOR THE YEAR ENDED MARCH 31, 2011	2010
Development costs	$ 1,454,000	$ 1,223,000
Exploration costs	—	620,000
Acquisitions:		
Proved	519,000	—
Unproved	756,000	313,000
Total costs of development, exploration and acquisition activities	**$ 2,729,000**	**$ 2,156,000**

Unaudited Oil and Gas Reserves Information

As of March 31, 2011 and 2010, 91% and 93%, respectively, of the estimated oil and gas reserves presented herein were derived from reports prepared by independent petroleum engineering firm Ryder Scott Company. The remaining 9% and 7% of the reserve estimates, respectively, were prepared internally by the Company's management.

Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves expected to be recovered through wells yet to be completed.

Analysis of Changes in Proved Reserves

Estimated quantities of proved developed reserves (all of which are located within the United States), as well as the changes in proved developed reserves during the periods indicated, are presented in the following tables:

	YEAR ENDED MARCH 31, 2011 OIL (Bbls)	2011 GAS (Mcf)	2010 OIL (Bbls)	2010 GAS (Mcf)	2009 OIL (Bbls)	2009 GAS (Mcf)
Proved reserves:						
Balance, beginning of year	818,000	912,000	638,000	936,000	1,074,000	1,120,000
Revisions of previous estimates [1]	167,000	(106,000)	275,000	195,000	(429,000)	(262,000)
Extensions and discoveries [2]	62,000	39,000	4,000	10,000	86,000	253,000
Improved recovery	6,000	61,000	—	—	—	—
Purchase of reserves	55,000	1,000	—	—	—	—
Production [3]	(93,000)	(172,000)	(99,000)	(229,000)	(93,000)	(175,000)
Balance, end of year	**1,015,000**	**735,000**	**818,000**	**912,000**	**638,000**	**936,000**
Proved developed reserves:						
Balance, beginning of year	727,000	912,000	587,000	907,000	1,074,000	1,120,000
Balance, end of year	**1,015,000**	**735,000**	**727,000**	**912,000**	**587,000**	**907,000**
Proved undeveloped reserves:						
Balance, beginning of year	91,000	—	51,000	29,000	—	—
Balance, end of year	**—**	**—**	**91,000**	**—**	**51,000**	**29,000**

[1] Revisions of Previous Estimates – Estimates reflect steady increases in oil and gas prices since December 2008, when prices reached a 5-year low. Changes in performance constitute less than 10% of the total amount of revisions of previous estimates.

[2] Extensions and Discoveries – Eleven wells represent extensions and discoveries during the year ended March 31, 2011, in North Dakota (7), Montana (2), Colorado (1) and Texas (1). Additions during the year ended March 31, 2010, consisted of 2 new wells in Colorado and 1 new well in North Dakota. Additions during the year ended March 31, 2009, pertained to the 16 wells drilled in Colorado.

[3] Production – Volumes of oil and gas that were produced were removed from reserves during the year.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

The table below sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved oil and gas reserves. Estimated future cash inflows were computed by applying the 12 month average price of oil and gas on the first day of each month (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves as of March 31, 2011 and 2010. Estimated future cash flows for the year ended March 31, 2009 were based on the spot price on the last day of the reporting period. This change is a result of the modified instructions from the SEC for reporting oil and gas activities, effective and adopted for the Company's year ended March 31, 2010. The future production and development costs represent the estimated future expenditures to be incurred in producing and developing the proved reserves, assuming continuation of existing economic conditions. Discounting the annual net cash flows at 10% illustrates the impact of timing on these future cash flows.

	YEAR ENDED MARCH 31,		
	2011	2010	2009
Future cash inflows	$ 81,053,000	$ 55,991,000	$ 31,793,000
Future cash outflows:			
Production cost	(41,185,000)	(29,065,000)	(17,924,000)
Development cost	—	(991,000)	(490,000)
Future income tax	(6,545,000)	(3,361,000)	(2,100,000)
Future net cash flows	**33,323,000**	**22,574,000**	**11,279,000**
Adjustment to discount future annual net cash flows at 10%	(15,826,000)	(10,060,000)	(4,080,000)
Standardized measure of discounted future net cash flows	**$ 17,497,000**	**$ 12,514,000**	**$ 7,199,000**

The following table summarizes the principal factors comprising the changes in the standardized measure of estimated discounted net cash flows for each of the years ended March 31, 2011, 2010, and 2009:

	YEAR ENDED MARCH 31,		
	2011	2010	2009
Standardized measure, beginning of year	$ 12,514,000	$ 7,199,000	$ 24,960,000
Sales of oil and gas, net of production cost	(5,204,000)	(4,284,000)	(5,808,000)
Net change in sales prices, net of production cost	5,886,000	6,279,000	(25,977,000)
Discoveries, extensions and improved recoveries, net of future development cost	1,567,000	154,000	2,298,000
Change in future development costs	—	467,000	—
Development costs incurred during the year that reduced future development cost	—	—	—
Sales of reserves in place	—	—	—
Revisions of quantity estimates	3,806,000	5,280,000	(4,745,000)
Accretion of discount	1,874,000	720,000	4,279,000
Net change in income tax	3,685,000	(1,582,000)	16,594,000
Purchase of reserves	1,408,000	—	—
Changes in timing of rates of production	(8,039,000)	(1,719,000)	(4,402,000)
Standardized measure, end of year	**$ 17,497,000**	**$ 12,514,000**	**$ 7,199,000**

FORWARD-LOOKING STATEMENTS

This Annual Report contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements are subject to risks and uncertainties and are based on the beliefs and assumptions of management and information currently available to management. The use of any statements containing the words "anticipate," "intend," "believe," "estimate," "project," "expect," "predict," "plan," "should," "likely," "may," "will," "continue" or similar expressions are intended to identify such statements. All statements other than statements of historical facts that address activities that we intend, expect or anticipate will or may occur in the future are forward-looking statements. All forward-looking statements should be evaluated with the understanding of their inherent uncertainty. Forward-looking statements relate to, among other things:

- our strategies, either existing or anticipated;
- our future financial position, including anticipated liquidity;
- our ability to satisfy obligations from cash generated from operations;
- amounts and nature of future capital expenditures;
- acquisitions and other business opportunities;
- operating costs and other expenses;
- wells expected to be drilled, other anticipated exploration efforts and the expenses associated therewith;
- our asset retirement obligation;
- estimates of proved oil and natural gas reserves, deferred tax assets, and depletion rates;
- our ability to meet additional acreage, seismic and/or drilling cost requirements arising from acquisition opportunities;
- other estimates and assumptions we use in our accounting policies; and
- future share repurchases.

Factors that could cause actual results to differ materially from our expectations include, among others, such things as:

- oil and natural gas prices;
- our ability to replace oil and natural gas reserves;
- loss of senior management or technical personnel;
- inaccuracy in reserve estimates and expected production rates;
- exploitation, development and exploration results;
- mechanical failure;
- the actual costs related to asset retirement obligation, and whether or not those retirements actually occur in the future;
- the potential unavailability of drilling rigs and other field equipment and services;
- the existence of unanticipated liabilities or problems relating to acquired properties;
- factors affecting the nature and timing of our capital expenditures, including the availability of service contractors and equipment;
- the willingness and ability of third parties to honor their contractual commitments;
- permitting issues;
- the nature, extent and duration of workovers;
- the impact and costs related to compliance with or changes in laws governing our operations;
- environmental liabilities;
- acquisitions and other business opportunities (or the lack thereof) that may be pursued by us;
- competition for available properties and the effect of such competition on the price of those properties;
- general economic, market or business conditions;
- weather;
- any change in interest rates or inflation;
- a lack of available capital and financing;
- risk factors consistent with comparable companies within our industry, especially companies with similar market capitalization and/or employee census; and
- other factors, many of which are beyond our control.

Furthermore, forward-looking statements are made based on our current assessment available at the time. Subsequently obtained information concerning the merits of any property, as well as changes in estimated exploration and development costs and ownership interest, may result in revisions to our expectations and intentions and, thus, we may alter our plans regarding any exploration and development activities.

Although we believe that the expectations reflected in such forward-looking statements are reasonable, those expectations may prove to be incorrect. As with comparable companies within our industry, there are numerous factors that could cause actual results to differ materially from our expectations. All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

MARKET FOR THE COMPANY'S COMMON STOCK

Price Range of Common Stock, Number of Holders and Dividend Policy

Effective December 31, 2010, the Board of Directors authorized and effected a 1-for-10 reverse stock split which converted ten (10) shares of the Company's common stock into one (1) share of common stock. All references in this Annual Report to the number of common shares, treasury shares, and per share amounts reflect the reverse stock split.

Our common stock is currently quoted on the NASDAQ Global Select Market under the ticker symbol "ESTE." Prior to January 26, 2011, our stock was traded on the Over-the-Counter Bulletin Board ("OTCBB") under the symbol "BSIC."

The closing bid price on NASDAQ of our common stock on June 27, 2011, was $13.85. The following table sets forth the quarterly high and low sales prices of our common stock as reported on NASDAQ for the period from January 26, 2011 through March 31, 2011:

	HIGH	LOW
Fourth Quarter [1]	$ 25.25	$ 13.56

[1] Our common stock commenced trading on NASDAQ on January 26, 2011.

The following table sets forth the range of high and low bid quotations of our common stock for each of the periods indicated below as reported by the OTCBB. These quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

	YEAR ENDED MARCH 31,			
	2011		2010	
	HIGH	LOW	HIGH	LOW
First Quarter	$ 14.40	$ 6.00	$ 9.90	$ 6.50
Second Quarter	13.00	9.20	9.50	7.30
Third Quarter	24.00	9.00	8.90	6.82
Fourth Quarter [1]	19.40	13.50	9.30	7.00

[1] Our common stock commenced trading on NASDAQ on January 26, 2011.

As of June 27, 2011, we had 1,961 shareholders of record. We have never paid a cash dividend on our common stock. Any future dividend on common stock will be at the discretion of the Board of Directors and will be dependent upon the Company's earnings and financial condition, receipt of our lender's consent and other factors. Our Board of Directors presently has no plans to pay any dividends in the foreseeable future.

CORPORATE INFORMATION

ANNUAL SHAREHOLDER MEETING

September 22, 2011
Time: 2:00 pm MDT

621 17th Street, Suite 1120
Denver, CO 80202

BOARD OF DIRECTORS

Ray Singleton
Chairman of the Board
President and Chief Executive Officer
Earthstone Energy, Inc.

Monroe W. Robertson
Retired Oil & Gas Executive
Chairman of the Audit Committee

Richard K. Rodgers
Vice President, Commercial Lending,
Mountain View Bank of Commerce
Chairman of the Compensation Committee

Andrew P. Calerich
Former Oil & Gas Excecutive

EXECUTIVE LEADERSHIP

Ray Singleton
President and Chief Executive Officer

Jim Poage
Interim Chief Financial Officer

CORPORATE HEADQUARTERS

Earthstone Energy, Inc.
633 17th Street, Suite 1645
Denver, CO 80202
303-296-3076

WEB SITE

Please visit the Company's web site at **www.EarthstoneEnergy.com** for more information on Earthstone Energy, Inc.

INVESTOR RELATIONS

Copies of Earthstone Energy's Annual Report and Form 10-K for the fiscal year ended March 31, 2011 are available at no charge. Please direct requests and investor relations questions to:

Ann Hadden-Good
303-296-3076 x112
info@EarthstoneEnergy.com

STOCK EXCHANGE LISTING

Trading Symbol: "ESTE" / NASDAQ

TRANSFER AGENT

First American Stock Transfer, Inc.
4747 N 7th Street, Suite 170
Phoenix, AZ 85014
877-271-0548

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ehrhardt Keefe Steiner & Hottman PC
7979 E Tufts Avenue, Suite 400
Denver, CO 80257

EARTHSTONE
Energy Inc.

633 17th Street, Suite 1645
Denver, CO 80202