The Road Ahead

Approach Resources Inc. **Annual Report 2009**

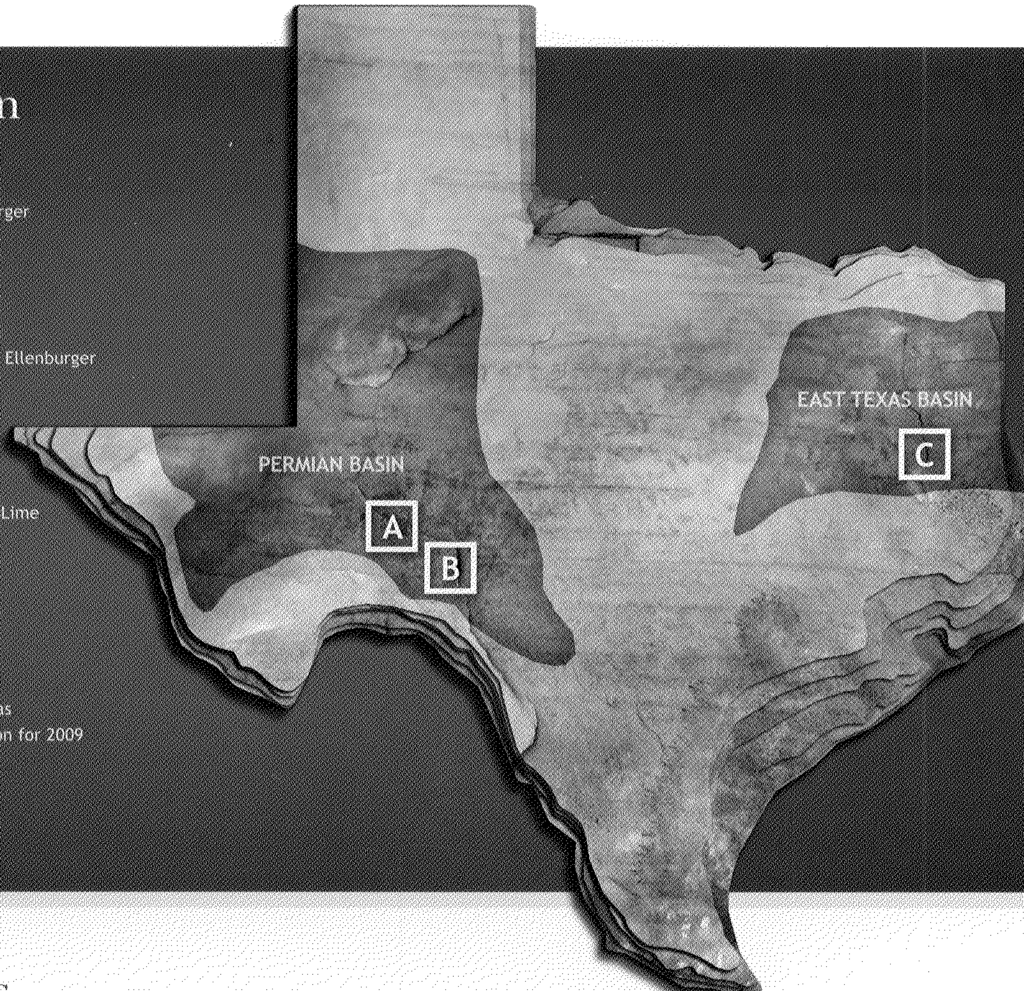
Core Areas *of* Operation

A Cinco Terry
- Wolfcamp, Canyon Sands and Ellenburger
- 68.7 Bcfe of proved reserves
- 50,281 gross (23,818 net) acres
- 558 identified drilling locations

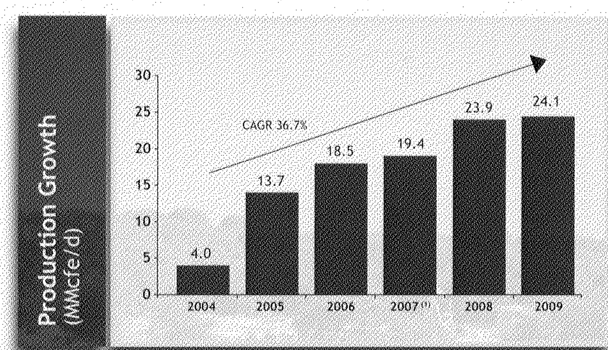
B Ozona Northeast
- Wolfcamp, Canyon Sands, Strawn and Ellenburger
- 134.8 Bcfe of proved reserves
- 49,850 gross (43,553 net) acres
- 660 identified drilling locations

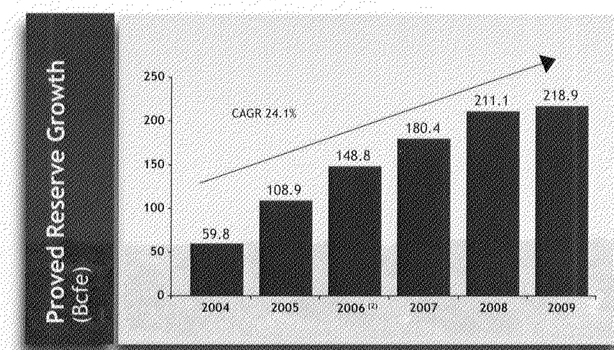
C North Bald Prairie
- Cotton Valley Sand and Cotton Valley Lime
- 15.5 Bcfe of proved reserves
- 8,006 gross (4,711 net) acres
- 93 identified drilling locations

Portfolio Highlights
- 218.9 Bcfe of proved reserves
- 43% proved developed, 77% natural gas
- 24.1 MMcfe/d average daily production for 2009
- 20+ year reserve life index
- 273,482 gross (196,634 net) acres
- 1,311 identified drilling locations
- 467 producing wells



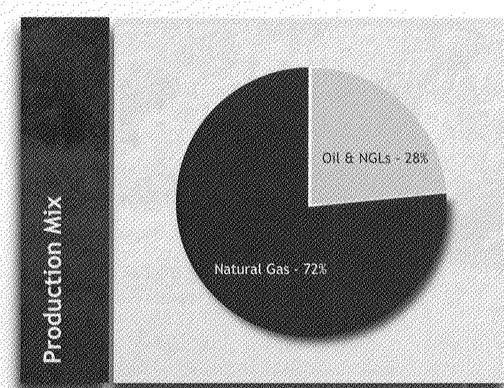
Production *and* Reserves





Information related to core areas of operation and production mix is as of December 31, 2009. In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in our Annual Report on Form 10-K for the year ended December 31, 2009, which was filed with the Securities and Exchange Commission on March 12, 2010.

(1) Pro forma for the November 2007 acquisition of 30% working interest in Ozona Northeast.
(2) Pro forma for working interest acquisition.



About Our Cover
U.S. Highway 190 takes you to our Cinco Terry field in the Permian Basin. In 2009, we increased reserves and production in Cinco Terry by 50% and 45%, respectively. With over 550 identified locations with multiple formation targets, Cinco Terry is an important asset for 2010 and the road ahead.

Financial *and* Operating Data

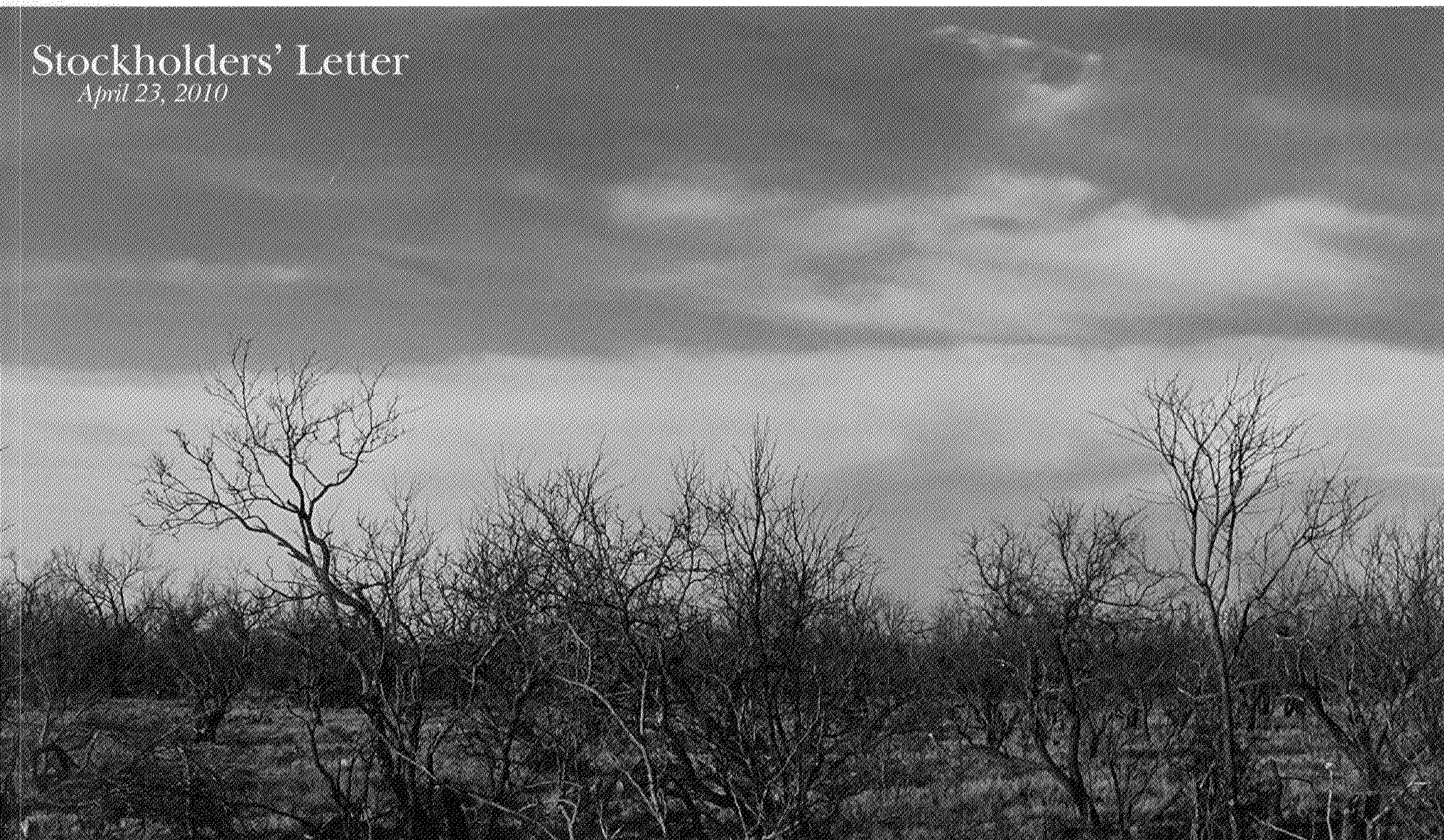
($ thousands, except per-unit and per-share amounts)

	2009	2008	2007
Revenues (in thousands):			
Gas	$ 23,406	$ 58,819	$ 33,497
Oil	11,323	16,413	5,062
NGLs	5,919	4,637	555
Total oil and gas sales	40,648	79,869	39,114
Realized gain on commodity derivatives	14,659	2,936	4,732
Total oil and gas sales including derivative impact	$ 55,307	$ 82,805	$ 43,846
Production:			
Gas (MMcf)	6,320	7,092	4,801
Oil (MBbls)	206	175	72
NGLs (MBbls)	209	102	12
Total (MMcfe)	8,808	8,755	5,305
Total (MMcfe/d)	24.1	23.9	14.5
Average prices:			
Gas (per Mcf)	$ 3.70	$ 8.29	$ 6.98
Oil (per Bbl)	54.97	93.79	70.31
NGLs (per Bbl)	28.32	45.46	46.25
Total (per Mcfe)	4.61	9.12	7.37
Realized gain on commodity derivatives (per Mcfe)	1.66	0.34	0.89
Total including derivative impact (per Mcfe)	6.27	9.46	8.26
Costs and expenses (per Mcfe):			
Lease operating	$ 0.88	$ 0.87	$ 0.72
Severance and production taxes	$ 0.23	$ 0.48	$ 0.31
Exploration	$ 0.18	$ 0.17	$ 0.17
Impairment of unproved properties	$ 0.34	$ 0.73	$ 0.05
General and administrative	$ 1.21	$ 1.01	$ 2.39
Depletion, depreciation and amortization	$ 2.80	$ 2.71	$ 2.47
Financial highlights:			
Net (loss) income	$ (5,229)	$ 23,386	$ 2,709
(Loss) earnings per diluted share	$ (0.25)	$ 1.12	$ 0.24
Adjusted net income*	$ 3,261	$ 23,483	$ 5,286
Adjusted net income per diluted share*	$ 0.16	$ 1.13	$ 0.47
EBITDAX*	$ 36,743	$ 63,201	$ 30,351
EBITDAX per diluted share*	$ 1.75	$ 3.03	$ 2.71
Weighted average shares outstanding (diluted)	20,870	20,825	11,184
Total long-term debt	$ 32,319	$ 43,537	$ –
Stockholders' equity	$ 220,496	$ 223,813	$ 199,819
Total assets	$ 318,926	$ 388,241	$ 248,726

**Adjusted net income and EBITDAX are non-GAAP financial measures. Reconciliations and other information on non-GAAP financial measures used in this report can be found following the 10-K and on the Non-GAAP Financial Information pages in the Investor Relations section of our website at www.approachresources.com.*

Stockholders' Letter

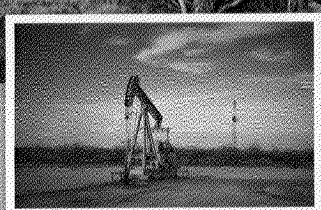
April 23, 2010

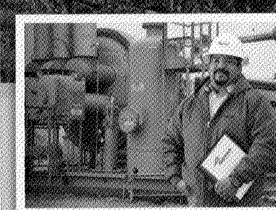


Dear Fellow Stockholders,

2009 was a year of challenge and opportunity, when natural gas prices reached seven-year lows, companies laid down drilling rigs and access to capital was severely limited. Despite the operational and financial challenges in the oil and gas industry, your Company strengthened its balance sheet, improved its liquidity and protected cash flow through the use of strategic hedges. During 2009, we focused on lowering costs, operating within cash flow and paying down debt.

As a result of these steps, I am pleased to report that in 2009 we increased our liquidity by over 40% to $85.4 million, cut our long-term debt by 26% to $32.3 million and reduced our long-term debt-to-capital ratio to 13%. In addition, we increased total proved reserves by 4% from 211 Bcfe to 219 Bcfe, held production stable at 8.8 Bcfe and replaced 345% of our production at a drill-bit finding and development cost of $0.97 per Mcfe, our lowest F&D cost since we started drilling in 2004. Faced with a weakening natural gas market, we also made the strategic decision to grow our oil and NGL production by 50% to 415,000 barrels in 2009, primarily through the continued development of our Cinco Terry field in the Permian Basin. For 2009, our production mix was 28% oil and NGLs and 72% natural gas. I believe each of these achievements marks success for Approach in 2009 in spite of the market conditions we faced during the year.

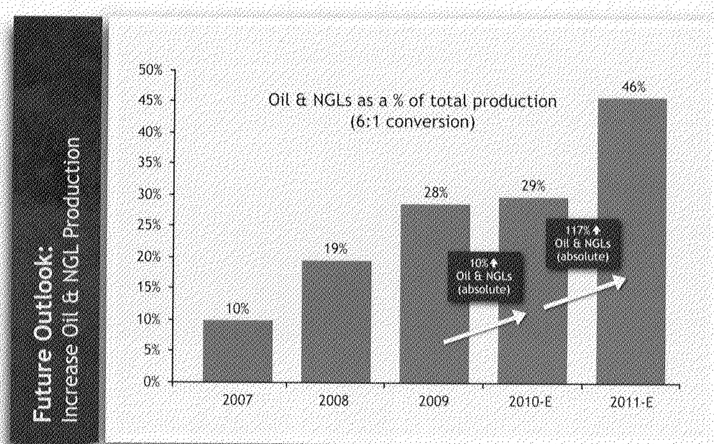



As we look past the first quarter of 2010, we believe we are well-positioned to adapt to today's market conditions. Our low finding and development costs, highly repeatable projects and solid rates of return are creating new opportunities at your Company. For 2010, we plan to allocate over 90% of our capital budget to our core, low-risk development drilling in the Permian Basin, where we lease over 100,000 gross acres. We also recently completed the acquisition of 3-D seismic data across our Cinco Terry acreage, which brings our total 3-D coverage to more than 135,000 acres in the Permian Basin.

Our Permian Basin assets are a critical component to our future growth for several reasons. First, our Canyon Sands wells are long-lived, with a stable, predictable decline rate and typical EURs of 480 to 550 MMcfe. We own an interest in over 450 wells and have identified 1,200 additional locations in the Permian, providing us with a solid base of existing production and a multi-year drilling inventory.

Second, our Permian acreage is characterized by stacked pay formations. The Canyon Sand is a reliable, tight gas producing zone, but we expect our 3-D seismic data, combined with our talented team of geoscientists, to be instrumental in helping us target the deeper, more prolific Ellenburger zone as well as potentially prospective shallower formations, including the Wolfcamp shale. With over 450 existing wellbores in Ozona Northeast and Cinco Terry, we believe the potential exists for economic recompletions and multi-zone production.

Third, our Permian plays include liquids-rich natural gas and oil. Our gas stream in Cinco Terry averages 1,220 Btu per Mcf, and a typical Canyon well with an EUR of 500 MMcfe will include 60,000 barrels of oil and NGLs. We expect 2010 development drilling in Cinco Terry alone should continue to increase the oil and NGL component of our total production and proved reserves. But we believe there is more to come.



After the first quarter of 2011, we will begin processing our wet gas from Ozona Northeast, which averages 1,250 Btu per Mcf, to unlock additional value and further grow the NGL component of our total production and proved reserves. Company wide, we believe that continued development of our existing Permian assets could drive our oil and NGL production to approximately 50% of our total production mix by the end of 2011.

During 2009, we were able to accomplish critical goals that we believe put us in a better position to deliver long-term growth and value for stockholders in 2010 and beyond. I am as excited about the opportunities for the coming months and years as I have ever been in more than 30 years in the business. I would like to thank our employees, business partners and fellow stockholders for your continued confidence in and support of Approach.

Sincerely,

J. Ross Craft
Director, President and Chief Executive Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 001-33801

APPROACH RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**51-0424817**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*
One Ridgmar Centre 6500 West Freeway, Suite 800 Fort Worth, Texas	**76116**
(Address of principal executive offices)	*(Zip Code)*

(Registrant's telephone number, including area code)

(817) 989-9000

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $0.01 per share	**NASDAQ Global Select Market**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates (excluding voting shares held by officers and directors) as of June 30, 2009 was $81.9 million. This amount is based on the closing price of the registrant's common stock on the NASDAQ Global Select Market on that date.

The number of shares of the registrant's common stock, par value $0.01, outstanding as of March 5, 2010 was 20,998,389.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2010 annual meeting of stockholders are incorporated by reference in Part III, Items 10-14 of this report.

Certain exhibits previously filed with the Securities and Exchange Commission are incorporated by reference into Part IV of this report.

APPROACH RESOURCES INC.

Unless the context otherwise indicates, all references in this report to "Approach," the "Company," "we," "us," "our" or "ours" are to Approach Resources Inc. and its subsidiaries. Unless otherwise noted, (i) all information in this report relating to oil and natural gas reserves and the estimated future net cash flows attributable to reserves is based on estimates and is net to our interest, and (ii) all information in this report relating to oil and natural gas production is net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the definitions of these terms under the caption "Glossary" at the end of Item 15 of this report.

TABLE OF CONTENTS

Cautionary Statement Regarding Forward-Looking Statements

Various statements in this report, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects, typical well economics and our future reserves, production, revenues, costs, income, capital spending, 3-D seismic operations, interpretation and results and obtaining permits and regulatory approvals. When used in this report, the words "will," "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project" or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

These forward-looking statements are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. We caution all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the "Risk Factors" section and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We expressly disclaim all responsibility to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- our business strategy;
- estimated quantities of oil and gas reserves;
- uncertainty of commodity prices in oil, gas and NGLs;
- global economic and financial market conditions;
- disruption of credit and capital markets;
- our financial position;
- our cash flow and liquidity;
- replacing our oil and gas reserves;
- our inability to retain and attract key personnel;
- uncertainty regarding our future operating results;
- uncertainties in exploring for and producing oil and gas;
- high costs, shortages, delivery delays or unavailability of drilling rigs, equipment, labor or other services;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our gas and other processing and transportation considerations;
- our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
- competition in the oil and gas industry;

- marketing of oil, gas and NGLs;
- interpretation of 3-D seismic data;
- exploitation of our current asset base or property acquisitions;
- the effects of government regulation and permitting and other legal requirements;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- other factors discussed under Item 1A. "Risk Factors" in this report.

PART I

Items 1. and 2. *Business and Properties.*

General

We are an independent energy company engaged in the exploration, development, production and acquisition of natural gas and oil properties. We focus on natural gas and oil reserves in tight sands and shale and have leasehold interests totaling approximately 273,482 gross (196,634 net) acres as of December 31, 2009. Our management and technical team has a proven track record of finding and exploiting unconventional reservoirs through advanced completion, fracturing and drilling techniques. As the operator of all of our production and estimated proved reserves, we have a high degree of control over capital expenditures and other operating matters.

We currently operate or have interests in the following areas:

West Texas

- Ozona Northeast (Wolfcamp, Canyon Sands, Strawn and Ellenburger)
- Cinco Terry (Wolfcamp, Canyon Sands and Ellenburger)

East Texas

- North Bald Prairie (Cotton Valley Sand, Bossier Shale and Cotton Valley Lime)

Northern New Mexico

- El Vado East (Mancos Shale)

Southwest Kentucky

- Boomerang (New Albany Shale)

At December 31, 2009, we owned working interests in 467 producing oil and gas wells, had estimated proved reserves of approximately 218.9 Bcfe and were producing 21.7 MMcfe/d, based on production for December 2009. Our 2010 average daily production through February was 22 MMcfe/d.

At December 31, 2009, all of our proved reserves and production were located in Ozona Northeast and Cinco Terry in West Texas and in North Bald Prairie in East Texas. At year end 2009, our proved reserves were 77% natural gas, 43% proved developed and had a reserve life index of over 20 years, based on 2009 production of 8,808 MMcfe. In addition to our producing wells, we have identified 1,311 total drilling locations in Ozona Northeast, Cinco Terry and North Bald Prairie at December 31, 2009, of which 385 are proved.

Approach was incorporated in 2002. Our common stock began trading on the NASDAQ Global Market in the United States under the symbol "AREX" on November 8, 2007. In December 2008, our common stock became listed on the NASDAQ Global Select Market, or NASDAQ. Our principal executive offices are located at One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116. Our telephone number is (817) 989-9000.

Business Strategy

Our objective is to build long-term stockholder value through growth in reserves and production in a cost-efficient manner. We intend to accomplish this objective by using a balanced program of (1) developing our core properties, (2) completing strategic acquisitions, (3) increasing our acreage, reserves and production through joint ventures, (4) operating as a low cost producer, (5) maintaining financial flexibility, and (6) exploring and exploiting our undeveloped properties. The following are key elements of our strategy:

- *Continue to develop our core properties.* We intend to develop further the significant remaining potential of our Ozona Northeast, Cinco Terry and North Bald Prairie properties, where we have identified 1,311 drilling locations. We believe we have the technical expertise and operational experience to maximize the value of these properties.
- *Acquire strategic assets.* We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects. We focus particularly on opportunities where we believe our reservoir management and geological and operational expertise in unconventional gas and oil properties will enhance value and performance. We remain focused on unconventional resource opportunities, but also look at conventional opportunities based on individual project economics.
- *Increase our land holdings, reserves and production through farm-ins and drilling ventures.* Our participation in a farm-in and a joint drilling venture has allowed us to grow our acreage position and reserves in Ozona Northeast (49,850 gross and 43,553 net acres and 134.8 Bcfe of proved reserves) and North Bald Prairie (8,006 gross and 4,711 net acres and 15.5 Bcfe of proved reserves). Farm-ins, joint drilling or "drill-to-earn" ventures and similar agreements can allow us to develop strategic, unconventional gas and oil properties for a substantially lower initial investment than acquiring the property outright.
- *Operate our properties as a low cost producer.* We seek to minimize our operating costs by concentrating our assets within geographic areas where we can consolidate operating control and thus create operating efficiencies. We operate all of our production and estimated proved reserves and plan to continue to operate a substantial portion of our producing properties in the future. Operating control allows us to better manage timing and risk as well as the cost of exploration and development, drilling and ongoing operations.
- *Maintain financial flexibility.* At December 31, 2009, we had $32.3 million in long-term debt outstanding under our revolving credit facility, with a borrowing base of $115 million, providing us with significant financial flexibility to pursue our business strategy. At February 28, 2010, we had $37.9 million in long-term debt outstanding under our credit facility. We intend to fund our 2010 capital expenditures, excluding any acquisitions, primarily out of internally-generated cash flows and, as necessary, borrowings under our revolving credit facility.
- *Exploit our undeveloped gas and oil opportunities.* We have an estimated 229,923 gross acres of undeveloped tight gas and shale gas and oil inventory to explore and produce. On a long-term basis, we believe we can add proved reserves and production from these properties through advanced technologies, including horizontal drilling and advanced fracing and completion techniques.

2009 Activity

In December 2008, we announced a capital expenditure budget of $43.8 million for 2009. Due to the extended decline of natural gas prices, in March 2009 we announced that we would not extend the contracts for our two remaining drilling rigs after March 31, 2009, and we released these rigs during the first week of April 2009. Overall for 2009, we increased production slightly from 8,755 MMcfe (23.9 MMcfe/d) in 2008 to 8,808 MMcfe (24.1 MMcfe/d) in 2009. However, the reduced drilling activity in the second and third quarters of 2009 and the natural decline of our tight gas fields resulted in a decline in our average daily production from 28.1 MMcfe/d for the three months ended March 31, 2009, to 21.6 MMcfe/d for the three months ended December 31, 2009.

A severe decline in natural gas, oil and NGL prices in 2009 adversely affected our results of operations. Our average realized price for natural gas, oil and NGLs (before the effect of commodity derivatives transactions) decreased 55.4%, 41.4% and 37.7%, respectively, from 2008 to 2009. Despite this adverse price environment, we were able to pay down our long-term debt and increase our liquidity by over 40%, from $60.5 million at December 31, 2008 to $85.4 million at December 31, 2009. We define liquidity as funds available under our credit facility plus year-end cash and cash equivalents. At December 31, 2009, we had $32.3 million in long-term debt outstanding under our revolving credit facility, compared to $43.5 million in long-term debt outstanding at December 31, 2008. The following table summarizes our liquidity position at December 31, 2009 compared to December 31, 2008:

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Borrowing base	$115,000	$100,000
Cash and cash equivalents	2,685	4,077
Long-term debt	(32,319)	(43,537)
Liquidity	$ 85,366	$ 60,540

In addition, as the result of our drilling in Cinco Terry, in 2009 we were able to increase our estimated proved reserves, net of production, by 4%, from 211,068 MMcfe at December 31, 2008, to 218,928 MMcfe at December 31, 2009. See Items 1. and 2. "Business and Properties — Proved Oil and Gas Reserves" for more information regarding our estimated proved reserves.

We resumed drilling during September 2009. Also during the fourth quarter of 2009, we began acquiring 3-D seismic data across 128.4 square miles, or 82,176 acres, in our Cinco Terry field.

Plans for 2010 Activity

At February 28, 2010, we were operating three rigs in our core Permian Basin development areas: two in Cinco Terry and one in Ozona Northeast. Our 2010 capital budget for development and exploration expenditures is $53 million. As we did during 2008 and 2009, we will continue to monitor commodity prices, operating expenses and drilling success to determine adjustments to the 2010 capital budget. The 2010 capital budget allocates $48.5 million to our core development properties in the Permian Basin and includes two rigs in Cinco Terry and one rig in Ozona Northeast until mid-year 2010, when we plan to add one rig in Ozona Northeast. The 2010 capital budget also allocates approximately $3.1 million to our exploratory prospects in Northern New Mexico and Southwest Kentucky. We intend to fund 2010 capital expenditures, excluding any acquisitions, primarily out of internally-generated cash flows and, as necessary, borrowings under our revolving credit facility.

We completed the acquisition of 3-D seismic data across our Cinco Terry field in February 2010. Our 3-D seismic data inventory now covers over 135,000 acres in the Permian Basin. Interpretation of the data is expected to be complete by June 2010.

We realize higher oil and NGL volumes in Cinco Terry than in Ozona Northeast (where we have a contract that does not include processing of NGLs) or North Bald Prairie (where substantially all of our production is dry gas). Therefore, as we have continued to develop Cinco Terry, we have increased the oil and NGL component of our overall production and reserves. In addition, our contract in Ozona Northeast expires in the first quarter of 2011, after which time we will begin processing our gas in Ozona Northeast. Excluding the effect of any future acquisitions, we expect that continued development of Cinco Terry in 2010 and beyond, along with processing gas in Ozona Northeast in 2011 and beyond, will continue to increase the oil and NGL component of our production and reserves in the future. NGLs are sold by the gallon, and in reporting proved reserves and production of NGLs, we convert NGLs to barrels of oil at the rate of 42 gallons per one Bbl of oil.

The following table summarizes our overall production and reserves over the past three years.

	Production		Reserves	
	Natural Gas (MMcf)	Oil & NGLs (MBbls)	Natural Gas (MMcf)	Oil & NGLs (MBbls)
December 31, 2009	6,320	415	168,334	8,432
Percent	72%	28%	77%	23%
December 31, 2008	7,092	277	172,867	6,367
Percent	81%	19%	82%	18%
December 31, 2007	4,801	84	161,151	3,208
Percent	90%	10%	89%	11%

Oil and Gas Properties and Operations

West Texas

Ozona Northeast (Wolfcamp, Canyon Sands, Strawn and Ellenburger)

The Ozona Northeast field in Crockett and Schleicher counties, Texas, is our largest operating area on the basis of proved reserves and production. We began operations in the field through a farm-in arrangement in 2004, and have increased our total acreage position to 49,850 gross (43,553 net) acres. We own substantially all working interests in all depths of the subsurface and have a net revenue interest of approximately 80% in Ozona Northeast. We also operate approximately 150 miles of gas gathering lines in the area. Beginning with our first well in February 2004, through December 31, 2009, we have drilled 312 successful wells out of 334 total wells drilled, for a 93% success rate. As of December 31, 2009, we had estimated proved reserves of 134.8 Bcfe in Ozona Northeast. As of February 28, 2010, we had one rig operating in Ozona Northeast.

Average daily production in 2009 was 14 MMcfe/d, or a total of 5,096 MMcfe. Average daily production in 2010 (through February) was 12.7 MMcfe/d. We have identified 660 additional drilling locations as of December 31, 2009, of which 204 are proved.

Cinco Terry (Wolfcamp, Canyon Sands and Ellenburger)

Since late 2005, we have leased and acquired options to lease 50,281 gross (23,818 net) acres in our Cinco Terry project, two miles northwest of Ozona Northeast, to explore the Wolfcamp, Canyon and Ellenburger formations. We have approximately a 52% working interest and 39% net revenue interest in Cinco Terry. Beginning with our first well in March 2006, through December 31, 2009, we have drilled 87 successful wells out of 100 total wells drilled, for an 87% success rate. As of December 31, 2009, we had estimated proved reserves of 68.7 Bcfe in Cinco Terry. As of February 28, 2010, we had two rigs operating in Cinco Terry.

Average daily production in 2009 was 9.3 MMcfe/d, or a total of 3,394 MMcfe. Average daily production in 2010 (through February) was 8.6 MMcfe/d. We have identified 558 additional drilling locations as of December 31, 2009, of which 157 are proved. We also own and operate seven miles of gas gathering lines in the area.

East Texas

North Bald Prairie (Cotton Valley Sands, Bossier and Cotton Valley Lime)

In July 2007, we entered into a joint drilling venture with EnCana Oil & Gas (USA) Inc., or EnCana, in the East Texas Cotton Valley/Bossier trend. As part of the joint venture, we agreed to drill up to five wells at our cost to earn a 50% working interest in the project. We began drilling operations in August 2007. As of December 31, 2009, we had drilled and completed 11 gross wells, including one well completed as a saltwater disposal well. We have a 50% working interest and approximately 40% net revenue interest. As of December 31, 2009, we had estimated proved reserves of 15.5 Bcfe in North Bald Prairie. Average daily production in 2009 was 0.9 MMcf/d, or a total of 318 MMcf. Average daily production in 2010 (through February) was 0.7 MMcf/d.

We believe the potential exists for producing from multiple zones in this area. Our primary targets are the Cotton Valley Sand, Bossier Shale and Cotton Valley Lime, all unconventional tight gas formations where we believe we can apply our geological, technical and operational expertise to successfully recover gas. Secondary targets include the shallower Rodessa, Pettit and Travis Peak formations. We have identified 93 potential drilling locations as of December 31, 2009.

We currently have no rigs running in North Bald Prairie. As previously reported, in December 2008, EnCana notified us that it was exercising its right to become the operator of record for joint interest wells in North Bald Prairie under the carry and earning agreement between the parties. We have continued to remain the operator of record pending payment by EnCana of joint interest billings owed to us under the joint operating agreement. In July 2009, our operating subsidiary filed a lawsuit against EnCana for failure to pay joint interest billings under the joint operating agreement. This proceeding is described in more detail in Part I, Item 3, "Legal Proceedings," and Note 10 to our consolidated financial statements in this report. The joint operating agreement, or JOA, allows either party to propose wells in the drilling project. In addition, we have re-leased or renewed approximately 2,461 net acres in the project at working interests of 100% as such acreage has expired or come up for renewal and EnCana has elected not to participate in such leases. We will continue to monitor commodity prices and offset acreage development to determine when to resume drilling in North Bald Prairie.

Northern New Mexico

El Vado East (Mancos Shale)

Our El Vado East prospect is a 90,357 gross (79,793 net) acre Mancos Shale play located in the Chama Basin in Northern New Mexico in proximity to several productive fields, including the Puerto Chiquito West, Puerto Chiquito East and the Boulder fields. Our primary objective in El Vado East is the Mancos Shale at 2,000 to 3,000 feet. We have a 90% working interest and a net revenue interest of approximately 72% in our El Vado East prospect. At December 31, 2009, we had no estimated proved reserves recorded for El Vado East.

Since Rio Arriba County, or the County, imposed a moratorium on permits for new oil and gas development on private lands in the County in April 2008, regulatory proceedings and an inability to timely obtain permits have delayed our drilling plans in El Vado East. In May 2009, the County lifted the drilling moratorium and enacted an oil and gas ordinance regulating oil and gas operations on private lands in the County. In addition to obtaining permits to drill from the State of New Mexico, we are now required to obtain special use permits from the County for drilling locations in El Vado East. The "force majeure" provisions of our mineral lease for El Vado East provide that if our drilling operations are delayed or prevented as a result of a governmental or regulatory order or by failure to obtain permits, then our commitments under the lease, including our initial drilling commitment of eight wells, will be extended for the period of force majeure, as long as the primary term of the lease is not extended by more than four years, or April 2013. We have invoked our right to assert force majeure under the lease and have received conditional approvals from the State for permits to drill 11 locations. We also have applied for special use permits from the County to drill eight locations. See Items 1. and 2. "Business and Properties — Regulation — New Mexico" for additional information on our New Mexico lease and the delays in drilling in New Mexico.

Southwest Kentucky

Boomerang (New Albany Shale)

Our Boomerang prospect is a 74,988 gross (44,759 net) acre New Albany Shale play located in Southwest Kentucky in the Illinois Basin. We have a 60% working interest and a net revenue interest of approximately 50%. Our capital budget for 2010 provides for the completion of two, previously-drilled wells in the New Albany Shale during 2010. Our technical team is also analyzing data from offset wells drilled to deeper formations and evaluating the purchase of 2-D seismic data to help define potentially deeper target zones. At December 31, 2009, we had no estimated proved reserves recorded for Boomerang.

Northeast British Columbia

Montney Tight Gas and Doig Shale

In August 2007, we acquired a non-operating, working interest ranging from 11.9% to 25% in a lease acquisition and drilling project targeting unconventional gas reserves in the emerging Montney tight gas and Doig Shale play in Northeast British Columbia.

We review our long-lived assets to be held and used, including proved and unproved oil and gas properties, accounted for under the successful efforts method of accounting. Based on the review of the recoverability of the carrying value of our unproved properties in Northeast British Columbia, we have recorded an impairment expense from a write-off of $3 million, related to all of our remaining carrying costs in this project. At December 31, 2009, we had no estimated proved reserves recorded for Northeast British Columbia, and no plans to develop the project. Acreage amounts in this report exclude Northeast British Columbia.

Proved Oil and Gas Reserves

Proved Reserves Reporting

On December 31, 2008, the Securities and Exchange Commission, or the SEC, released a Final Rule, *Modernization of Oil and Gas Reporting*, approving revisions designed to modernize oil and gas reserve reporting requirements. The new reserve rules are effective for our financial statements for the year ended December 31, 2009 and our 2009 year-end proved reserve estimates. The most significant revisions to the reporting requirements include:

- *Commodity prices.* Economic producibility of reserves is now based on the unweighted, arithmetic average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, unless prices are defined by contractual arrangements;
- *Undeveloped oil and gas reserves.* Reserves may be classified as "proved undeveloped" for undrilled areas beyond one offsetting drilling unit from a producing well if there is reasonable certainty that the quantities will be recovered;
- *Reliable technology.* The rules now permit the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;
- *Unproved reserves.* Probable and possible reserves may be disclosed separately on a voluntary basis;
- *Preparation of reserves estimates.* Disclosure is required regarding the internal controls used to assure objectivity in the reserves estimation process and the qualifications of the technical person primarily responsible for preparing reserves estimates; and
- *Third party reports.* We are now required to file the report of any third party used to prepare or audit reserves our estimates.

We adopted the rules effective December 31, 2009, as required by the SEC.

Proved Reserves Table

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2009. See Note 12 to our consolidated financial statements for additional information. Our estimated total proved reserves of natural gas, oil and NGLs as of December 31, 2009 were 218.9 Bcfe. The 2009 reserves are composed of 77% natural gas and 23% oil, condensate and NGLs. The proved developed portion of total proved reserves at year end 2009 was 43%. We determined the natural gas equivalent of oil, condensate and NGLs by using a conversion ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs.

The standardized measure of discounted future net cash flows for our proved reserves at December 31, 2009 was $80 million. The PV-10 of our estimated proved reserves at December 31, 2009, was $128.9 million.

Summary of Oil and Gas Reserves as of Fiscal-Year End
Based on Average Fiscal-Year Prices

	Reserves		
Reserves Category	Natural Gas (MMcf)	Oil & NGLs (MBbls)	Total (MMcfe)
PROVED			
Developed:			
Ozona Northeast	61,265	463	64,043
Cinco Terry	11,827	2,655	27,757
North Bald Prairie	1,712	—	1,712
Total	74,804	3,118	93,512
Undeveloped:			
Ozona Northeast	65,350	896	70,724
Cinco Terry	14,408	4,418	40,920
North Bald Prairie	13,772	—	13,772
Total	93,530	5,314	125,416
TOTAL PROVED at December 31, 2009	168,334	8,432	218,928

Effect of New Proved Reserves Reporting Requirements

The new reserve rules resulted in the use of lower prices for natural gas, oil and NGLs than would have resulted under the previous reporting requirements. Under the previous reserve rules, our estimated total proved reserves of natural gas, oil and NGLs would have been 231.2 Bcfe. Therefore, the effect of the new reserve rules was a negative revision of 12.3 Bcfe.

The new reserve rules limit the recording and maintaining of proved undeveloped reserves locations to those scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time. This new reserve rules did not affect our estimates of proved reserves.

Preparation of Proved Reserves Estimates

Internal Controls Over 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 and prepared in accordance with generally accepted petroleum engineering principles. Our Manger of Reservoir Engineering, John J. Marting, P.E., is the individual responsible for overseeing the preparation of our reserve estimates and for internal compliance of our reserve estimates with SEC rules, regulations and generally accepted petroleum engineering principles. Mr. Marting has a Bachelor of Science degree in Petroleum Engineering (Cum Laude) from the University of Missouri-Rolla and over 30 years of industry experience. Mr. Marting reports directly to our Chief Executive Officer. Our senior management, including our Chief Executive Officer and Chief Financial Officer, reviews our reserves estimates before these estimates are finalized and disclosed in a public filing or presentation.

For the years ended December 31, 2009, 2008 and 2007, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties. See *Third Party Reports* below for further information regarding DeGolyer & MacNaughton's report.

Technologies Used in Preparation of Proved Reserves Estimates

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

When applicable, the volumetric method was used to estimate the original oil in place, or OOIP, and the original gas in place, or OGIP. Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

Because our proved reserves are located in depletion-type reservoirs and reservoirs whose performance demonstrates a reliable decline in producing-rate trends, reserves were also estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-declining curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses or leases as appropriate.

Third Party Reports

For the years ended December 31, 2009, 2008 and 2007, we engaged DeGolyer and MacNaughton, independent, third-party reserves engineers, to prepare estimates of the extent and value of the proved reserves of certain of our oil and gas properties. The estimates for 2009, 2008 and 2007 included a detailed review of our Ozona Northeast, Cinco Terry and North Bald Prairie fields, or 100% of our total proved reserves. DeGolyer and MacNaughton's report for 2009 is included as Exhibit 99.1 to this annual report on Form 10-K.

Reserves Sensitivity Analysis

The following table provides an estimate of our proved reserves based on a "Current Price Case" calculated under the new reserve rules, and a "Previous Price Case" calculated under the previous reserve rules.

Sensitivity of Reserves to Prices by Principal Product Type and Price Scenario

	Proved Reserves			
Price Case	**Natural Gas (MMcf)**	**Oil & NGLs (MBbls)**	**Total (MMcfe)**	**PV-10**
Current Price Case	168,334	8,432	218,928	$128,936
Previous Price Case	178,354	8,806	231,190	$317,440

Proved reserve volumes and PV-10 in the Current Price Case were estimated based on the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2009 for natural gas, oil and NGLs. Natural gas volumes were calculated based on the average Henry Hub spot price of $3.87 per MMBtu. Oil volumes were calculated based on the average West Texas

Intermediate, or WTI, posted price of $61.04 per Bbl. NGL volumes were calculated based on the average price received on the first day of each month during 2009 of $27.20 per Bbl. All prices were adjusted for energy content, quality and basis differentials by field and were held constant through the lives of the properties.

Proved reserve volumes and PV-10 in the Previous Price Case were estimated based on the posted spot price as of December 31, 2009, for natural gas, oil and NGLs. Natural gas volumes were calculated based on the Henry Hub spot price of $5.79 per MMBtu. Oil volumes were calculated based on the WTI posted price of $76.00 per Bbl. NGL volumes were calculated based on the Mont Belvieu posted price of $42.94 per Bbl. All prices were adjusted for energy content, quality and basis differentials by field and were held constant through the lives of the properties.

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. PV-10 is a non-GAAP, financial measure and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

The following table shows our reconciliation of our PV-10 to the standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP). The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value."

As of December 31, 2009	Current Price Case	Previous Price Case
	(In thousands)	
PV-10	$128,936	$ 317,440
Less income taxes:		
Undiscounted future income taxes	(88,796)	(256,144)
10% discount factor	39,851	139,625
Future discounted income taxes	(48,945)	(116,519)
Standardized measure of discounted future net cash flows	$ 79,991	$ 200,921

We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis.

Proved Undeveloped Reserves

As of December 31, 2009, we had 125.4 Bcfe of proved undeveloped reserves, or PUDs, which is an increase of 16.7 Bcfe or 15.3%, compared with 108.8 Bcfe of PUDs at December 31, 2008. Approximately 89% of our PUDs at December 31, 2009 were associated with our core development properties in the Permian Basin: Ozona Northeast (56%) and Cinco Terry (33%). The remaining 11% of our PUDs at year-end 2009 were associated with our North Bald Prairie field in East Texas.

We added 25.7 Bcfe of PUDs in 2009 through our drilling program, consisting of 20.6 Bcfe of extensions and discoveries in Cinco Terry and 5.1 Bcfe of extensions and discoveries in Ozona Northeast. Partially offsetting extensions and discoveries was a negative revision of 3.5 Bcfe in Ozona Northeast and North Bald Prairie due to lower commodity prices. We also removed 5.6 Bcfe of PUDs due to performance revisions primarily attributable to North Bald Prairie.

We invested approximately $3.5 million to convert 1 Bcfe of PUDs in Cinco Terry to proved developed in 2009. Estimated future development costs relating to the development of PUDs are projected to be approximately $59.8 million in 2010, $55.4 million in 2011 and $45.6 million in 2012. All PUDs are scheduled to be drilled before the end of 2014.

We have 2.6 Bcfe of PUDs, or approximately 1% of our total proved reserves, that have been booked for five years or longer. These reserves are located in Ozona Northeast. As discussed in Items 1. and 2. "Business and Properties — 2009 Activity," of this report, we reduced our drilling activity in 2009 in response to a sharp decline in natural gas prices. As of February 28, 2010, we had resumed drilling in Ozona Northeast with one rig. We plan to add a second rig in Ozona Northeast by mid-year 2010 and drill a total of 36 gross wells in 2010. Despite the expected increase in drilling in Ozona Northeast in 2010, the volume of PUDs in Ozona Northeast that will have been booked for five years or longer at December 31, 2010, will increase from December 31, 2009 and, depending on the timing and selection of locations to be drilled in Ozona Northeast in 2010, such increase might be material. We have a history of significant development activity in Ozona Northeast, as we have drilled over 330 gross (over 250 net) wells there since our first well in February 2004, and we intend to continue the development of PUDs in Ozona Northeast over time.

Oil and Gas Production, Production Prices and Production Costs

The following table sets forth summary information regarding natural gas, oil and NGL production, average sales prices and average production costs, by geographic area, for the last three years. We determined the natural gas equivalent of oil, condensate and NGLs by using a conversion ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs.

	Oil and Gas Production			
	Natural Gas (MMcf)	Oil (MBbl)	NGLs (MBbl)	Total (MMcfe)
Year Ended December 31, 2009				
Ozona Northeast	4,654	74	—	5,096
Cinco Terry	1,348	132	209	3,394
North Bald Prairie	318	—	—	318
Total	6,320	206	209	8,808
Year Ended December 31, 2008				
Ozona Northeast	5,567	68	—	5,976
Cinco Terry	1,078	107	102	2,332
North Bald Prairie	447	—	—	447
Total	7,092	175	102	8,755
Year Ended December 31, 2007				
Ozona Northeast	4,719	58	—	5,067
Cinco Terry	82	14	12	238
Total	4,801	72	12	5,305

	Average Sales Price(1)				Production Cost
	Natural Gas (Per Mcf)	Oil (Per Bbl)	NGLs (Per Bbl)	Total (Per Mcfe)	$/Per Mcfe(2)
Year Ended December 31, 2009					
Ozona Northeast	$3.79	$ 59.96	$ —	$4.29	$0.69
Cinco Terry	3.37	53.85	28.32	5.18	0.65
North Bald Prairie	3.78	—	—	3.78	1.32
Total	$3.70	$ 54.97	$28.32	$4.61	$0.70
Year Ended December 31, 2008					
Ozona Northeast	$8.54	$102.46	$ —	$9.11	$0.74
Cinco Terry	7.37	89.23	45.46	9.49	0.66
North Bald Prairie	7.42	—	—	7.42	1.07
Total	$8.29	$ 93.79	$45.46	$9.12	$0.72
Year Ended December 31, 2007					
Ozona Northeast	$7.00	$ 69.98	$ —	$7.32	$0.52
Cinco Terry	5.82	83.58	46.25	8.55	0.79
Total	$6.98	$ 70.31	$46.25	$7.37	$0.53

(1) Average sales price for 2009, 2008 and 2007 excludes the positive effect of commodity derivatives of $1.66/Mcfe, $0.34/Mcfe and $0.89/Mcfe, respectively.

(2) Production cost per Mcfe is composed of lease operating expenses excluding ad valorem taxes. Production cost per Mcfe also excludes severance and production taxes.

Producing Wells

The following table sets forth the number of producing wells in which we owned a working interest at December 31, 2009. Wells are classified as natural gas or oil according to their predominant production stream.

	Natural Gas Wells		Oil Wells		Total Wells		
	Gross	Net	Gross	Net	Gross	Net	Average Working Interest
Ozona Northeast	371	361	1	1	372	362	97%
Cinco Terry	76	38	10	5	86	43	50%
North Bald Prairie	9	4.5	—	—	9	4.5	50%
Total	456	403.5	11	6	467	409.5	88%

Drilling Activity

The following table sets forth information on our drilling activity for the last three years. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	28.0	16.0	83.0	54.5	51.0	46.0
Non-productive	4.0	2.0	11.0	7.5	5.0	4.0
Exploratory wells:						
Productive	—	—	—	—	—	—
Non-productive	—	—	2.0	0.5	1.0	0.7
Total wells:						
Productive	28.0	16.0	83.0	54.5	51.0	46.0
Non-productive	4.0	2.0	13.0	8.0	6.0	4.7

Of the 28 gross productive wells drilling 2009, four (three net) wells were waiting on completion at December 31, 2009, and have since been completed as producers.

Of the 11 gross development non-productive wells drilled in 2008, one well was completed as a saltwater disposal well in North Bald Prairie during 2009. The two gross exploratory, non-productive wells drilled in 2008 were drilled by the Canadian operator of our Northeast British Columbia project.

Although a well may be classified as productive upon completion, future changes in oil and gas prices, operating costs and production may result in the well becoming uneconomical.

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2009.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	29,760	28,944	20,090	14,609	49,850	43,553
Cinco Terry	10,318	5,263	39,963	18,555	50,281	23,818
North Bald Prairie	3,481	1,687	4,525	3,024	8,006	4,711
El Vado East	—	—	90,357	79,793	90,357	79,793
Boomerang	—	—	74,988	44,759	74,988	44,759
Total	43,559	35,894	229,923	160,740	273,482	196,634

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2009 that will expire over the next three years by project area unless production is established prior to the expiration dates:

	2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	—	14	9,983	11,620	6,321	2,410
Cinco Terry	7,192	4,172	11,642	6,183	7,833	5,002
North Bald Prairie	1,050	563	—	—	335	254
El Vado East	90,357	79,793	—	—	—	—
Boomerang	6,777	4,066	146	88	725	435
Total	105,376	88,608	21,771	17,891	15,214	8,101

Undeveloped acreage in our Boomerang prospect assumes the exercise of options to extend the current primary terms by four to five additional years (beginning June 2010 through May 2012) on 67,340 gross (40,171 net) acres. Options to extend 58,548 gross (35,027 net) acres have an exercise price of $2 per year per net acre for five total available years. Options to extend 5,860 gross (3,480 net) acres have an exercise price of $6 per year per net acre for five total available years. Options to extend 1,650 gross (894 net) acres have an exercise price of $7 per year per net acre for five total available years. Options to extend the remaining 1,282 gross (769 net) acres have a weighted average exercise price of $38 per net acre for four to five total available years.

Undeveloped acreage in our El Vado East prospect is subject to an eight-well drilling commitment during the primary term of the mineral lease, which expired in April 2009. As of the filing of this annual report on Form 10-K, the primary term was extended by force majeure under the lease, up to April 2013. If we meet the drilling commitment (as extended by force majeure), we will have two options to extend the primary term by one year each for $15 per net acre, for a total extension of two years at $30 per net acre. If we are not able to meet the drilling commitment, during the extended primary term, and we are otherwise not able to negotiate appropriate extensions under the lease, the lease will expire. See Items 1. and 2. "Business and Properties — Regulation — New Mexico" for additional information on our New Mexico lease and the delays in drilling in New Mexico.

Markets and Customers

The revenues generated by our operations are highly dependent upon the prices of, and supply and demand for, oil and gas. The price we receive for our oil and gas production depends on numerous factors beyond our control, including seasonality, the condition of the United States and global economies, particularly in the manufacturing sectors, political conditions in other oil and gas producing countries, the extent of domestic production and imports of oil and gas, the proximity and capacity of gas pipelines and other transportation facilities, supply and demand for oil and gas, the marketing of competitive fuels and the effects of federal, state and local regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

During the year ended December 31, 2009, Ozona Pipeline Energy Company, which we refer to as Ozona Pipeline, WTG Benedum/Belvan Partners, LP and Shell Trading U.S. Company, which we refer to as Shell, were our most significant purchasers, accounting for approximately 43.3%, 26.1% and 22.4%, respectively, of our total 2009 oil and gas sales excluding realized commodity derivative settlements.

Commodity Derivative Activity

We enter into financial swaps and collars to mitigate portions of the risk of market price fluctuations related to future oil and gas production.

All derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are currently recognized in the statement of operations unless specific commodity derivative accounting criteria are met and contracts have been designated as cash flow hedge instruments. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive (loss) income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in accumulated other comprehensive (loss) income are reclassified to oil and gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow commodity derivatives. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized (loss) gain on commodity derivatives."

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make a general investigation of title at the time we acquire undeveloped properties. We receive title opinions of counsel before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use of the properties in the operation of our business.

Competition

The oil and gas industry is highly competitive, and we compete for prospective properties, producing properties and personnel with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, attracting highly-skilled personnel and obtaining purchasers and transporters of the oil and gas we produce. We also face competition from alternative fuel sources, including coal, heating oil, imported LNG, nuclear and other nonrenewable fuel sources, and renewable fuel sources such as wind, solar, geothermal, hydropower and biomass. Competitive conditions may also be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the United States government. However, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Regulation

The oil and gas industry in the United States is subject to extensive regulation by federal, state and local authorities. At the federal level, various federal rules, regulations and procedures apply, including those issued by the United States Department of Interior, and the United States Department of Transportation (Office of

Pipeline Safety). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Various remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines and penalties or otherwise subject us to the various remedies as are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with these federal, state and local rules, regulations and procedures.

Transportation and Sale of Gas

The Federal Energy Regulatory Commission, or FERC, regulates interstate gas pipeline transportation rates and service conditions. Although FERC does not regulate gas producers such as us, the agency's actions are intended to foster increased competition within all phases of the gas industry and its regulation of third-party pipelines and facilities could indirectly affect our ability to transport or market our production. To date, FERC's pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the gas industry will have on our gas sales efforts.

FERC or other federal or state regulatory agencies may consider additional proposals or proceedings that might affect the gas industry. In addition, new legislation may affect the industries and markets in which we operate. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any of these proposals will affect us any differently than other gas producers with which we compete.

Regulation of Production

Oil and gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells. Also, each state generally imposes an ad valorem, production or severance tax with respect to production and sale of oil, gas and gas liquids within its jurisdiction.

Environmental Regulations

In the United States, the exploration for and development of oil and gas and the drilling and operation of wells, fields and gathering systems are subject to extensive federal, state and local laws and regulations governing environmental protection as well as discharge of materials into the environment. Similar environmental laws exist in Canada. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling production, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate and remediate pollution from historical and ongoing operations, such as the closure of waste pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and criminal penalties. The effects of existing and future laws and regulations could have a material adverse impact on our business, financial condition and results of operations. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this will continue in the future.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, or CERCLA, also known as the Superfund law, and comparable state statutes impose strict, and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA.

Waste Handling

The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development, exploitation and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for oil and gas exploration, production and development activities. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on, under or from the properties owned or leased by us or on, under or from other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or contamination, or to perform remedial activities to prevent future contamination.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of hazardous and toxic air pollutants at specified sources. These regulatory programs may require us to obtain permits before commencing construction on a new source of air emissions and may require us to reduce emissions at existing facilities. As a result, we may be required to incur increased capital and operating costs. Additionally, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and analogous state laws and regulations.

In February 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change, which we refer to as the Protocol, entered into force. Pursuant to the Protocol, adopting countries are required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, which are suspected of contributing to global warming. The United States is not currently a participant in the Protocol. However, Congress has enacted legislation directed at reducing greenhouse gas emissions and the EPA may be required to regulate greenhouse gas emissions, and many states have already adopted legislation or undertaken regulatory initiatives addressing greenhouse gas emissions from various sources. The oil and gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions would likely adversely impact our future operations, results of operations and financial condition. At this time, although it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business, passage of such laws or regulation affecting areas in which we conduct business could have an adverse effect on our operations.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations that apply to our current operations and that our ongoing compliance with existing requirements will not have a material adverse effect on our financial condition or results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2009. In addition, as of the date of this annual report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2010. However, the passage of more stringent laws or regulations in the future could have a negative effect on our business, financial condition and results of operations, including our ability to develop our undeveloped acreage. For example, see our discussion of current regulatory proceedings in New Mexico below.

New Mexico

In April 2008, the Board of County Commissioners of Rio Arriba County, New Mexico, or the County, imposed a moratorium on all oil and gas drilling on private lands the County, pending the adoption of an ordinance that would regulate oil and gas operations. The moratorium covered all of our El Vado East prospect in the County. In May 2009, the Board of County Commissioners lifted the moratorium and adopted a final oil and gas drilling ordinance. The ordinance requires special use permits for oil and gas operations in the eastern part of the County where our El Vado East prospect is located.

Our mineral lease for El Vado East currently requires us to drill a minimum of eight wells before the end of the primary term of the lease, which originally was set to expire on April 2, 2009. However, the drilling moratorium, regulatory proceedings and an inability to obtain permits delayed our drilling plans in El Vado East and, accordingly, we have invoked our right to assert "force majeure" under our mineral lease and extended the primary term of the lease during the period of force majeure, up to a maximum of four years past the original primary term, or April 2, 2013.

In November 2009, the New Mexico Oil Conservation Division conditionally approved our applications for permits to drill for 11 locations in El Vado East. In December 2009, the County's Planning & Zoning Commission conditionally approved our applications for special use permits for five drilling locations in El Vado East. We have filed applications for special use permits with the County for a total of eight drilling locations. These applications are subject to final approval of the County's Board of County Commissioners.

Assuming no further, unexpected delays in the permitting process, we believe we will be able to satisfy our initial drilling commitment before the end of the primary term as extended by force majeure. However, our inability to timely meet this drilling commitment or negotiate appropriate extensions under the lease could result in the termination of the lease and write-off of our investment in El Vado East, the current carrying value of which is $2.9 million.

Employees

At February 28, 2010, we had 45 full-time employees, 19 of whom are field personnel. We regularly use independent contractors and consultants to perform various field and other services. None of our employees are represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are excellent.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Available Information

We maintain an internet website under the name *www.approachresources.com*. The information on our website is not a part of this report. We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the charters of our Audit Committee and Compensation and Nominating Committee, and our Code of Conduct, are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Approach, that file electronically with the SEC. The public can obtain any document we file with the SEC at *www.sec.gov*. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. *Risk Factors.*

You should carefully consider the risk factors set forth below as well as the other information contained in this report before investing in our common stock. Any of the following risks could materially and adversely affect our business, financial condition or results of operations. In such a case, you may lose all or part of your investment. The risks described below are not the only risks facing us. Additional risks and uncertainties not currently known to us or those we currently view to be immaterial may also materially adversely affect our business, financial condition or results of operations.

Risks Related to the Oil and Natural Gas Industry and Our Business

Oil and gas prices are volatile, and a decline in oil or gas prices could significantly affect our business, financial condition or results of operations and our ability to meet our capital expenditure requirements and financial commitments.

Our revenues, profitability and cash flow depend substantially upon the prices and demand for oil and gas. The markets for these commodities are volatile, and even relatively modest drops in prices can affect significantly our financial results and impede our growth. Prices for oil and gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control, such as:

- the level of domestic and foreign consumer demand for oil and gas;
- domestic and foreign supply of oil and gas, including LNG;
- overall United States and global economic conditions;
- price and availability of alternative fuels;
- price and quantity of foreign imports;
- commodity processing, gathering and transportation availability and the availability of refining capacity;
- domestic and foreign governmental regulations;
- political conditions in or affecting other gas producing and oil producing countries;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- weather conditions, including unseasonably warm winter weather and tropical storms; and
- technological advances affecting oil and gas consumption.

Further, oil prices and gas prices do not necessarily fluctuate in direct relationship to each other. Because more than 77% of our estimated proved reserves as of December 31, 2009 were gas reserves, our financial results are more sensitive to movements in gas prices. Recent gas prices have been extremely volatile and we expect this volatility to continue. For example, from January 1, 2009 to December 31, 2009, the NYMEX gas spot price ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu.

The results of higher investment in the exploration for and production of oil and gas and other factors, such as global economic and financial conditions discussed below, may cause the price of gas to fall. Lower oil and gas prices may not only cause our revenues to decrease but also may reduce the amount of oil and gas that we can produce economically. Substantial decreases in oil and gas prices would render uneconomic some or all of our drilling locations. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our business, financial condition and results of operations. Further, if oil and gas prices significantly decline for an extended period of time, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future debt or obtain additional capital on attractive terms, all of which can affect the value of our common stock.

Changes in the differential between NYMEX or other benchmark prices of oil and gas and the reference or regional index price used to price our actual oil and gas sales could have a material adverse effect on our financial condition or results of operations.

The reference or regional index prices that we use to price our oil and gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict oil and gas differentials. Changes in differentials between the benchmark price for oil and gas and the reference or regional index price we reference in our sales contracts could have a material adverse effect on our results of operations and financial condition.

Future economic conditions in the U.S. and international markets could materially and adversely affect our business, financial condition or results of operations.

The U.S. and other world economies continue to experience the effects of a global recession and credit market crisis. More volatility may occur before a sustainable growth rate is achieved either domestically or globally. Even if such growth rate is achieved, such a rate may be lower than the U.S. and international economies have experienced in the past. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower, future economic growth rate will result in decreased demand for our oil and gas production and lower commodity prices, which will reduce our cash flows from operations and our profitability.

Difficult conditions in the credit and capital markets may limit our ability to obtain funding under our current revolving credit facility or other sources of debt or equity financing. The inability to obtain funding could prevent us from meeting our future capital needs to fund our development program.

Credit and capital markets have experienced unprecedented volatility and disruption. Although markets began to recover in 2009, they may remain volatile and unpredictable, particularly if weaker than expected economic growth persists. We have a significant inventory of development properties that will require substantial future investment. We will need financing to fund these and other activities. Our future access to capital could be limited if the credit or broader capital markets are constrained. This could prevent or significantly delay development of our assets.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2009, we had approximately $32.3 million of outstanding debt under our revolving credit facility, and our borrowing base was $115 million. The borrowing base limitation under our credit facility is semi-annually redetermined based upon a number of factors, including commodity prices and reserve levels. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any 12-month period. Upon a redetermination, our borrowing base could be substantially reduced, and if the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. We use cash flow from operations and bank borrowings to fund our exploration and development activities. A reduction in our borrowing base could limit those activities. In addition, we may significantly change our capital structure to make future acquisitions or develop our properties. Changes in capital structure may significantly increase our debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

Drilling and exploring for, and producing, oil and gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Drilling and exploration are the main methods we use to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- inadequate capital resources;
- unavailability or high cost of drilling rigs, equipment or labor;
- compliance with governmental regulations;
- unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents;
- lack of acceptable prospective acreage;
- adverse weather conditions;
- surface access restrictions;
- title problems; and
- mechanical difficulties.

The use of geophysical and geological analyses and other technical or operating data to evaluate drilling prospects is uncertain and does not guarantee drilling success or recovery of economically producible reserves.

Our decisions to explore, develop and acquire prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater pre-drilling expenditures than traditional drilling strategies.

Currently, all of our producing properties are located in three counties in Texas, making us vulnerable to risks associated with having our production concentrated in a small area.

All of our producing properties and estimated proved reserves are geographically concentrated in three counties in Texas, Crockett, Schleicher and Limestone. Our current production is primarily attributable to three fields in Crockett and Schleicher Counties, Ozona Northeast and the Angus and Holt fields in Cinco Terry. As a result of this concentration, we are disproportionately exposed to the natural decline of production from these fields, and particularly Ozona Northeast, as well as the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailments of production, natural disasters, interruption of transportation of gas produced from the wells in these fields or other events that impact these areas.

Identified drilling locations that we decide to drill may not yield oil or gas in commercially viable quantities and are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our drilling locations are in various stages of evaluation, ranging from locations that are ready to be drilled to locations that will require substantial additional evaluation and interpretation. There is no way to predict before drilling and testing whether any particular drilling location will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively before drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. The analysis that we perform may not be useful in predicting the characteristics and potential reserves associated with our drilling locations. As a result, we may not find commercially viable quantities of oil and gas.

Our drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including oil and gas prices, costs, the availability of capital, seasonal conditions, regulatory approvals and drilling results. Because of these uncertainties, we do not know when the drilling locations we have identified will be drilled or if they will ever be drilled or if we will be able to produce oil or gas from these or any proved drilling locations. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations or financial condition.

Unless we replace our oil and gas reserves, our reserves and production will decline.

Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of our proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve reports. These differences may be material.

The proved oil and gas reserve information included in this report represents estimates. Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production and operating costs incurred;

- the amount and timing of future development expenditures; and
- future oil and gas prices.

As of December 31, 2009, approximately 57% of our proved reserves were proved undeveloped. Estimates of proved undeveloped reserves are even less reliable than estimates of proved developed reserves.

Furthermore, different reserve engineers may make different estimates of reserves and future net revenues based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The PV-10 included in this report should not be considered as the current market value of the estimated oil and gas reserves attributable to our properties. PV-10 is based on the unweighted, arithmetic average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, while actual future prices and costs may be materially higher or lower. If natural gas, oil and NGL prices decline by 10% from the Current Price Case ($3.87 per MMBtu, $61.04 per Bbl of oil and $27.20 per Bbl of NGLs to $3.48 per MMBtu, $54.94 per Bbl of oil and $24.48 per Bbl of NGLs), then our PV-10 as of December 31, 2009, would decrease from $128.9 million to $86.4 million. The average market price received for our production for the month of December 31, 2009 was $5.84 per Mcf (after basis and Btu adjustments), $70.61 per Bbl of oil and $43.12 per Bbl of NGLs.

Actual future net revenues also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production will increase the demand for oilfield services, and the costs of these services may increase, while the quality of these services may suffer. We currently are experiencing increased demand for drilling rigs, crews and certain oilfield services in the Permian Basin, our primary area of operation. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel becomes particularly severe in the Permian Basin, we could be materially and adversely affected because our operations and properties are concentrated in the Permian Basin.

We have leases and options for undeveloped acreage that may expire in the near future.

As of December 31, 2009, we held mineral leases or options in each of our areas of operations that are still within their original lease term and are not currently held by production. Unless we establish commercial production on the properties subject to these leases, most of these leases will expire between 2010 and 2015. If these leases or options expire, we will lose our right to develop the related properties. See Items 1. and 2. "Business and Properties — Undeveloped Acreage Expirations" for a table summarizing the expiration schedule of our undeveloped acreage over the next three years.

Competition in the oil and gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and gas and securing equipment and trained personnel. Many of our competitors are major and large independent oil and gas companies that possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Our customer base is concentrated, and the loss of our key customers could, therefore, adversely affect our financial results.

In 2009, Ozona Pipeline, WTG Benedum/Belvan Partners, LP and Shell accounted for approximately 43.3%, 26.1% and 22.4%, respectively, of our total oil and gas sales excluding realized commodity derivative settlements. To the extent that Ozona Pipeline, WTG Benedum/Belvan Partners or Shell reduces their purchases in gas or oil or defaults on their obligations to us, we would be adversely affected unless we were able to make comparably favorable arrangements with other customers. These purchasers' default or non-performance could be caused by factors beyond our control. A default could occur as a result of circumstances relating directly to one or both of these customers, or due to circumstances related to other market participants with which the customer has a direct or indirect relationship.

We depend on our management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition and the results of operations and future growth.

Our success largely depends on the skills, experience and efforts of our management team and other key personnel. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial condition, results of operations and future growth. We have entered into employment agreements with J. Ross Craft, our President and Chief Executive Officer and Steven P. Smart, our Executive Vice President and Chief Financial Officer. If either of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

We have three affiliated stockholders who, together with our board and management, have a 42% interest in our company, whose interests may differ from your interests and who will be able to control or substantially influence the outcome of matters voted upon by our stockholders.

At December 31, 2009, Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P. and Yorktown Energy Partners VII, L.P., or collectively, Yorktown, which are under common management, beneficially owned approximately 32% of our outstanding common stock in the aggregate, together with a Yorktown representative who serves on our board of directors. In addition, our non-Yorktown directors and management team beneficially own or control approximately 10% of our common stock outstanding. As a result of this ownership and control, Yorktown, together with our board and management, has the ability to control or substantially influence the vote in any election of directors. Yorktown, together with our board and management, also has control or substantial influence over our decisions to enter into significant corporate transactions and, in their capacity as our majority stockholders, these stockholders may have the ability to effectively block any transactions that they do not believe are in Yorktown's or management's best interest. As a result, Yorktown, together with our board and management, is able to control, directly or indirectly and subject to applicable law, or substantially influence all matters affecting us, including the following:

- any determination with respect to our business direction and policies, including the appointment and removal of officers;
- any determinations with respect to mergers, business combinations or dispositions of assets;
- our capital structure;
- compensation, option programs and other human resources policy decisions;
- changes to other agreements that may adversely affect us; and
- the payment, or nonpayment, of dividends on our common stock.

Yorktown, together with our board and management, also may have an interest in pursuing transactions that, in their judgment, enhance the value of their respective equity investments in our company, even though those transactions may involve risks to you as a minority stockholder. In addition, circumstances could arise under which their interests could be in conflict with the interests of our other stockholders or you, a minority stockholder. Also, Yorktown and their affiliates have and may in the future make significant investments in other companies, some of which may be competitors. Yorktown and its affiliates are not obligated to advise us of any investment or business opportunities of which they are aware, and they are not restricted or prohibited from competing with us.

We have renounced any interest in specified business opportunities, and certain members of our board of directors and certain of our stockholders generally have no obligation to offer us those opportunities.

In accordance with Delaware law, we have renounced any interest or expectancy in any business opportunity, transaction or other matter in which our outside directors and certain of our stockholders, each referred to as a Designated Party, participates or desires to participate in that involves any aspect of the exploration and production business in the oil and industry. If any such business opportunity is presented to a Designated Person who also serves as a member of our board of directors, the Designated Party has no obligation to communicate or offer that opportunity to us, and the Designated Party may pursue the opportunity as he sees fit, unless:

- it was presented to the Designated Party solely in that person's capacity as a director of our company and with respect to which, at the time of such presentment, no other Designated Party has independently received notice of or otherwise identified the business opportunity; or
- the opportunity was identified by the Designated Party solely through the disclosure of information by or on behalf of us.

As a result of this renunciation, our outside directors should not be deemed to be breaching any fiduciary duty to us if they or their affiliates or associates pursue opportunities as described above and our future competitive position and growth potential could be adversely affected.

We are subject to complex governmental laws and regulations that may adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and gas, and operating safety, and protection of the environment, including those relating to air emissions, wastewater discharges, land use, storage and disposal of wastes and remediation of contaminated soil and groundwater. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may encounter reductions in reserves or be required to make large and unanticipated capital expenditures to comply with governmental laws and regulations, such as:

- price control;
- taxation;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions; and
- permitting requirements.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs, soil and groundwater remediation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed, and our cost of operations could significantly increase as a result of environmental safety and other regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects. Intricate and changing environmental and other regulatory requirements may require substantial expenditures to obtain and maintain permits. If a project is unable to function as planned, for example, due to costly or changing requirements or local opposition, it may create expensive delays, extended periods of non-operation or significant loss of value in a project. See Items 1. and 2., "Business and Properties — Regulation."

Possible regulation related to global warming and climate change could have an adverse effect on our business, financial condition or results of operations and demand for natural gas and oil.

In June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill or ACESA. Further, on November 5, 2009, the United States Senate passed out of committee the Clean Energy Jobs and American Power Act, also known as the Boxer-Kerry Bill. These bills contain provisions that would establish a cap and trade system for restricting greenhouse gas emissions in the United States. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this federal legislative initiative remains uncertain.

In addition to pending climate legislation, the Environmental Protection Agency, or EPA, has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding could lead to regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules this year.

In the courts, several decisions have been issued that could increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays or lower returns on our capital investments.

Congress currently is considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing, or "fracing," process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us for many of the wells that we drill and operate. Supporters of legislation currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process may adversely impact drinking water. The proposed legislation could lead to (i) additional legal challenges to the fracing process based on alleged impact to drinking water or (ii) restrictions on the fluids that can be used in the process. Additional regulation and legal challenges could lead to operational delays and increased compliance and operating costs. Restrictions on fluids used in the fracing process could negatively impact the productivity of our future drilling locations, lower our return on capital expenditures and have a material adverse effect on our business, financial condition, results of operations and quantities of oil and gas reserves that may be economically produced.

Changes in tax laws may adversely affect our results of operations and cash flows.

President Obama's Proposed Fiscal Year 2011 Budget includes proposed legislation that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and natural gas properties;
- the elimination of current deductions for intangible drilling costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

Derivatives regulation could restrict our ability to execute commodity derivative transactions to protect against risk associated with fluctuating commodity prices.

Various measures are being proposed by committees of Congress, the U.S. Treasury Department, and other agencies to restrict the use of over-the-counter, or OTC, derivative instruments. These proposals include, but are not limited to, requiring cash collateral on all OTC derivatives and requiring all OTC derivatives to be executed and settled through an exchange system. Although we do not currently know the exact form any final legislation or rule-making activity will take, any restriction on the use of OTC instruments could have a significant impact on our business. Limits on the use of OTC instruments could significantly reduce our ability to execute strategic commodity derivatives transactions to reduce price uncertainty and to protect cash flows. In addition, cash collateral requirements could create significant burdens on our liquidity and exchange system trades may restrict our ability to execute derivative instruments to fit our strategic needs.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and gas business involves certain operating hazards such as:

- well blowouts;
- cratering;
- explosions;
- uncontrollable flows of gas, oil or well fluids;
- fires;
- pollution; and
- releases of toxic gas.

The occurrence of one of the above may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties.

In addition, our operations in Texas are especially susceptible to damage from natural disasters such as tornados and involve increased risks of personal injury, property damage and marketing interruptions. Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, exploitation and acquisition, or could result in a loss of our properties. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs are expected to continue to increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

Our results are subject to quarterly and seasonal fluctuations.

Our quarterly operating results have fluctuated in the past and could be negatively impacted in the future as a result of a number of factors, including:

- seasonal variations in oil and gas prices;
- variations in levels of production; and
- the completion of exploration and production projects.

Market conditions or transportation impediments may hinder our access to oil and gas markets or delay our production.

Market conditions and the unavailability of satisfactory oil and gas processing and transportation may hinder our access to oil and gas markets or delay our production. Although currently we control the gathering system operations for a majority of our production in Ozona Northeast, we do not have such control over the regional or downstream pipelines in Ozona Northeast or in other areas where we operate or expect to conduct operations. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In addition, the amount of oil and gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases we are provided with limited, if any, notice as to when these circumstances will arise and their duration. As a result, we may not be able to sell, or may have to transport by more expensive means, the oil and gas production from wells or we may be required to shut in gas wells or delay initial production until the necessary gathering and transportation systems are available. Any significant curtailment in gathering system or pipeline capacity, or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition or results of operations.

Environmental liabilities may expose us to significant costs and liabilities.

There is inherent risk of incurring significant environmental costs and liabilities in our oil and gas operations due to the handling of petroleum hydrocarbons and generated wastes, the occurrence of air emissions and water discharges from work-related activities and the legacy of pollution from historical industry operations and waste disposal practices. We may incur joint and several or strict liability under these environmental laws and regulations in connection with spills, leaks or releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities, many of which have been used for exploration, production or development activities for many years, oftentimes by third parties not under our control. Private parties, including the owners of properties upon which we conduct drilling and production activities as well as facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance. See Items 1. and 2., "Business and Properties — Regulation."

Our growth strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make acquisitions or realize anticipated benefits of those acquisitions.

Our growth strategy may include acquiring oil and gas businesses and properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully. Furthermore, acquisitions involve a number of risks and challenges, including:

- diversion of management's attention;
- the need to integrate acquired operations;
- potential loss of key employees of the acquired companies;
- potential lack of operating experience in a geographic market of the acquired business; and
- an increase in our expenses and working capital requirements.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses or realize other anticipated benefits of those acquisitions.

Joint drilling ventures and similar arrangements could expose us to risks.

As the operator in a joint drilling venture, we could be exposed to a risk of loss if a non-operating participant fails to meet its obligations to fund its portion of the drilling and operating costs as agreed under a joint operating or other applicable agreement. In addition, as a non-operator in a joint drilling venture, we could have limited or no ability to influence or control the future development of non-operated properties or the amount of capital expenditures that we are required to fund. The failure of an operator to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues and increase our capital expenditures and operating costs. When we are the non-operator, our dependence on an operator and our limited ability to influence or control operations and future development could have a material adverse effect on our business, financial condition or results of operations.

Severe weather could have a material adverse impact on our business.

Our business could be materially and adversely affected by severe weather. Repercussions of severe weather conditions may include:

- curtailment of services;
- weather-related damage to drilling rigs, resulting in suspension of operations;
- weather-related damage to our facilities;
- inability to deliver materials to jobsites in accordance with contract schedules; and
- loss of productivity.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occurs or escalates, the resulting political instability and societal disruption could reduce overall demand for oil and gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Oil and gas related facilities could be direct targets for terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities we use for the production, transportation or marketing of our oil and gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become difficult to obtain, if available at all.

Risks Related to Our Financial Condition

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to fully implement our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flows, borrowings under our revolving credit facility and issuances of common stock. We also require capital to fund our exploration and development budget. As of December 31, 2009, approximately 57% of our total estimated proved reserves were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. According to our year-end 2009 reserve report, the estimated capital required to develop our current proved developed and proved undeveloped oil and gas reserves is $213 million. We will be required to meet our needs from our internally-generated cash flows, debt financings and equity financings.

If our revenues decrease as a result of lower commodity prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. Our revolving credit facility contains covenants restricting our ability to incur additional indebtedness without lender consent. There can be no assurance that our bank lenders will provide this consent or as to the availability or terms of any additional financing. If we incur additional debt, the related risks that we now face could intensify.

Even if additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations and available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our projects, which in turn could lead to a possible loss of properties and a decline in our oil and gas reserves.

Our bank lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2009, we had $32.3 million in outstanding borrowings under our revolving credit facility, and our borrowing base was $115 million. The borrowing base under our revolving credit facility is redetermined semi-annually. Redeterminations are based upon information contained in an annual reserve report prepared by an independent petroleum engineering firm and a mid-year report prepared by our own engineers. In addition, as is typical in the oil and gas industry, our bank lenders have substantial flexibility to reduce our borrowing base on the basis of subjective factors. Upon a redetermination, we could be required to repay a portion of our outstanding borrowings, including the total face amounts of all outstanding letters of credit and the amount of all unpaid reimbursement obligations, to the extent such amounts exceed the redetermined borrowing base. We may not have sufficient funds to make such required repayment, which could result in a default under the terms of the revolving credit facility and an acceleration of the loan. We intend to finance our development, exploration and acquisition activities with cash flow from operations, borrowings under our revolving credit facility and other financing activities. In addition, we may significantly alter our capital structure to make future acquisitions or develop our properties. Changes in our capital structure may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher debt level also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which will be affected by general economic conditions and financial, business and other factors. Many of these factors are beyond our control. Our level of debt affects our operations in several important ways, including the following:

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

We engage in commodity derivative transactions which involve risks that can harm our business.

To manage our exposure to price risks in the marketing of our gas production, we enter into gas price and basis differential commodity derivative agreements. While intended to reduce the effects of volatile gas prices and basis differentials, such transactions may limit our potential gains and increase our potential losses if gas prices were to rise substantially over the price established by the commodity derivative, or if the basis spread decreases substantially from the basis differential established by the commodity derivative. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative arrangement or the counterparties to the commodity derivative agreements fail to perform under the contracts. In addition, as discussed above in this Item 1A. "Risk Factors," proposed legislation relating to derivatives transactions may restrict our ability to execute transactions to protect against risks of fluctuating commodity prices.

Risks Related to Our Common Stock

Our stock price may fluctuate significantly.

Our common stock began trading on the NASDAQ Global Market in November 2007. In December 2008, our common stock began trading on the NASDAQ Global Select Market. An active trading market may not be sustained. In 2009, the average daily trading volume of our common stock was 62,721 shares, or 0.3% of our weighted average shares outstanding for the year. The market price of our common stock could fluctuate significantly as a result of:

- the relatively low trading volume and resulting price swings associated with above-average sales or purchases of our common stock;
- actual or anticipated quarterly variations in our operating results;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- announcements relating our business or the business of our competitors;
- conditions generally affecting the oil and gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other, comparable companies.

Many of these factors are beyond our control and we cannot predict their potential effects on the price of our common stock. In addition, the stock markets in general can experience considerable price and volume fluctuations.

Future sales of our common stock may cause our stock price to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

Common stockholders will be diluted if additional shares are issued.

In our initial public offering in November 2007, we sold 8.8 million shares of common stock to repay $51.1 million outstanding on our revolving credit facility and to repurchase 2 million shares of common stock from the selling stockholder. In connection with the offering, we also acquired the 30% working interest in Ozona Northeast that we did not already own from the selling stockholder in exchange for 4.2 million shares of common stock. We may issue additional shares of common stock, preferred stock, depositary shares, warrants, rights, units and debt securities for general corporate purposes, including repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We also issue restricted stock to our executive officers, employees and independent directors as part of their compensation. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

The equity trading markets may be volatile, which could result in losses for our stockholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition.

Item 1B. *Unresolved Staff Comments.*

None.

Item 3. *Legal Proceedings.*

Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A, District Court of Limestone County, Texas. On July 2, 2009 our operating subsidiary filed a lawsuit against EnCana Oil & Gas (USA) Inc., or EnCana, for breach of the joint operating agreement, or JOA, covering our North Bald Prairie project in East Texas and seeking damages for nonpayment of amounts owed under the JOA as well as declaratory relief. We contend that such amounts owed by EnCana are at least $2.1 million, plus attorneys' fees, costs and other amounts to which we might be entitled under law or in equity. As we previously have disclosed, in December 2008, EnCana notified us that it was exercising its right to become operator of record for joint interest wells in North Bald Prairie under an operator election agreement between the parties. EnCana contends that it does not owe us for part or all of joint interest billings incurred after EnCana provided us with notice of EnCana's election to assume operatorship in December 2008. EnCana also contends that certain of the disputed operations were unnecessary, while other charges are improper because we failed to obtain EnCana's consent under the JOA prior to undertaking the operations. We have informed the Court that we will transfer operatorship to EnCana when EnCana has made all payments it owes under the JOA.

Regardless of the outcome of this proceeding, the JOA provides that either party (operator or non-operator) may propose the drilling of wells.

We also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

Item 4. *(Removed and Reserved).*

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Market Information

Our common stock is traded on NASDAQ in the United States under the symbol "AREX." During 2009, trading volume averaged 62,721 shares per day. The following table shows the quarterly high and low sale prices of our common stock as reported on NASDAQ for the past two years.

	High	Low
2009		
First quarter	$ 8.90	$ 3.20
Second quarter	10.47	5.13
Third quarter	9.77	6.38
Fourth quarter	10.19	6.24
2008		
First quarter	$17.38	$ 9.20
Second quarter	28.87	15.17
Third quarter	30.00	9.92
Fourth quarter	14.25	5.39

Holders

As of February 28, 2010, there were 37 record holders of our common stock. In many instances, a record holder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Dividends

We have not paid any cash dividends on our common stock. We do not expect to pay any cash or other dividends in the foreseeable future on our common stock, as we intend to reinvest cash flow generated by operations in our business. Our revolving credit facility currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Securities Authorized for Issuance under Equity Compensation Plans

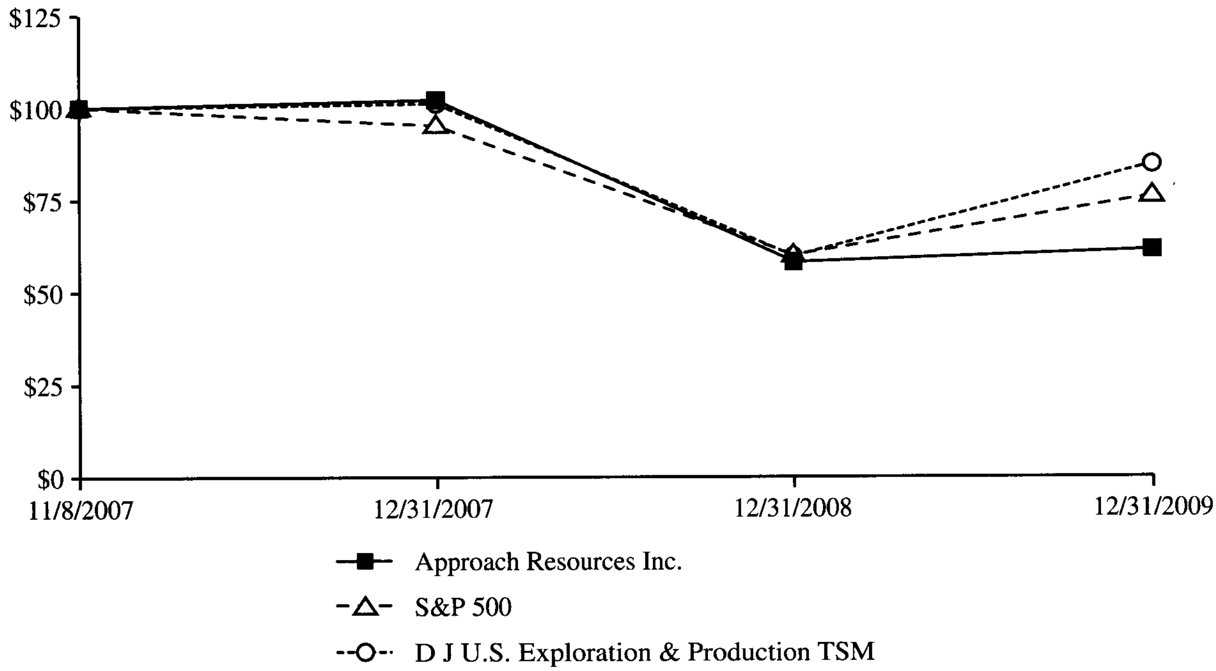
The following table sets forth information regarding securities authorized for issuance under equity compensation plans and individual compensation arrangements as of December 31, 2009.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by stockholders	409,327	$8.03	1,242,064
Equity compensation plans not approved by stockholders	—	—	—

Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from November 8, 2007, through December 31, 2009, to that of the cumulative return on a $100 investment in the Standard & Poor's 500, or S&P 500, index and the Dow Jones U.S. Exploration & Production Total Stock Market, or TSM, index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

Comparison of Total Return from November 8, 2007 through December 31, 2009
Among Approach Resources Inc., the S&P 500 Index and
the Dow Jones U.S. Exploration & Production TSM Index



	11/8/2007	12/31/2007	12/31/2008	12/31/2009
Approach Resources Inc.	$100.00	$102.14	$58.06	$61.32
S&P 500	100.00	95.15	59.95	75.81
D J U.S. Exploration & Production TSM	100.00	101.09	59.62	84.37

Recent Sales of Unregistered Securities; Uses of Proceeds From Registered Securities

We did not sell any securities during the year ended December 31, 2009 that were not registered under the Securities Act.

Issuer Repurchases of Equity Securities

We adopted the Approach Resources Inc. 2007 Stock Incentive Plan effective as of June 28, 2007, and amended it effective December 31, 2008. The 2007 Stock Incentive Plan allows us to withhold shares of common stock to pay withholding taxes payable upon vesting of a restricted stock grant. The number of shares of common stock available for grants under the 2007 Stock Incentive Plan is increased by the number of shares withheld as payment of such withholding taxes. The following table shows the number of shares of common stock withheld to satisfy the income tax withholding obligations arising upon the vesting of restricted shares issued to employees under the 2007 Stock Incentive Plan.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet be Purchased Under the Plans or Programs
October 1, 2009 — October 31, 2009	—	—	—	—
November 1, 2009 — November 30, 2009	5,835	$7.50	—	—
December 1, 2009 — December 31, 2009	—	—	—	—
Total	5,835	$7.50	—	—

Item 6. ***Selected Financial Data.***

The following table sets forth selected financial information for the five years ended December 31, 2009. All weighted average shares and per share data have been adjusted for the three-for-one stock split and the stock issuance resulting from the combination of Approach Oil & Gas Inc., or AOG, under a contribution agreement effective November 14, 2007. This information should be read in conjunction with Item 7 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements, related notes and other financial information included in this report.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per-share data)				
Operating Results Data					
Revenues					
Oil and gas sales	$ 40,648	$ 79,869	$ 39,114	$ 46,672	$ 43,264
Expenses					
Lease operating	7,777	7,621	3,815	3,889	2,910
Severance and production taxes	1,996	4,202	1,659	1,736	1,975
Exploration	1,621	1,478	883	1,640	733
Impairment of unproved properties	2,964	6,379	267	558	—
General and administrative	10,617	8,881	12,667	2,416	2,659
Depletion, depreciation and amortization	24,660	23,710	13,098	14,551	8,011
Total expenses	49,635	52,271	32,389	24,790	16,288
Operating (loss) income	(8,987)	27,598	6,725	21,882	26,976
Other					
Impairment of investment	—	(917)	—	—	—
Interest expense, net	(1,787)	(1,269)	(5,219)	(3,814)	(802)
Realized gain on commodity derivatives	14,659	2,936	4,732	6,222	(2,925)
Unrealized (loss) gain on commodity derivatives	(9,899)	7,149	(3,637)	8,668	(4,163)
(Loss) income before (benefit) provision for income taxes	(6,014)	35,497	2,601	32,958	19,086
(Benefit) provision for income taxes	(785)	12,111	(108)	11,756	7,028
Net (loss) income	$ (5,229)	$ 23,386	$ 2,709	$ 21,202	$ 12,058
(Loss) earnings per share					
Basic	$ (0.25)	$ 1.13	$ 0.25	$ 2.26	$ 1.32
Diluted	$ (0.25)	$ 1.12	$ 0.24	$ 2.20	$ 1.32
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$ 39,761	$ 56,435	$ 30,746	$ 34,305	$ 40,588
Investing activities	(29,553)	(100,633)	(52,940)	(59,384)	(72,224)
Financing activities	(11,618)	43,696	22,062	26,771	32,199
Effect of Canadian exchange rate	18	(206)	6	—	—
Balance Sheet Data					
Cash and cash equivalents	$ 2,685	$ 4,077	$ 4,785	$ 4,911	$ 3,219
Other current assets	9,318	30,760	12,021	12,792	15,701
Property, equipment, net, successful efforts method	304,483	303,404	230,819	132,520	89,407
Other assets	2,440	—	1,101	86	89
Total assets	$318,926	$ 338,241	$248,726	$150,309	$108,416
Current liabilities	$ 21,996	$ 30,775	$ 22,017	$ 15,421	$ 32,746
Long-term debt	32,319	43,537	—	47,619	29,425
Other long-term liabilities	44,115	40,116	26,890	17,697	6,555
Stockholders' equity	220,496	223,813	199,819	69,572	39,690
Total liabilities and stockholders' equity	$318,926	$ 338,241	$248,726	$150,309	$108,416

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

The following discussion is intended to assist in understanding our results of operations and our financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this report contain additional information that should be referred to when reviewing this material. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, which could cause actual results to differ from those expressed. See "Cautionary Statement Regarding Forward-Looking Statements" at the beginning of this report and "Risk Factors" in Item 1.A for additional discussion of some of these factors and risks.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of natural gas and oil properties. We focus on natural gas and oil reserves in tight sands and shale and have leasehold interests totaling approximately 273,482 gross (196,634 net) acres as of December 31, 2009. Our management team has a proven track record of finding and exploiting unconventional reservoirs through advanced completion, fracturing and drilling techniques. As the operator all of our production and proved reserves, we have a high degree of control over capital expenditures and other operating matters.

We currently operate or have interests in the following areas:

West Texas

- Ozona Northeast (Wolfcamp, Canyon Sands, Strawn and Ellenburger)
- Cinco Terry (Wolfcamp, Canyon Sands and Ellenburger)

East Texas

- North Bald Prairie (Cotton Valley Sand, Bossier Shale and Cotton Valley Lime)

Northern New Mexico

- El Vado East (Mancos Shale)

Southwest Kentucky

- Boomerang (New Albany Shale)

At December 31, 2009, we owned working interests in 467 producing oil and gas wells, had estimated proved reserves of approximately 218.9 Bcfe and were producing 21.7 MMcfe/d, based on production for December 2009. Our 2010 average daily production through February was 22 MMcfe/d.

At December 31, 2009, all of our proved reserves and production were located in Ozona Northeast and Cinco Terry in West Texas and in North Bald Prairie in East Texas. At year end 2009, our proved reserves were 77% natural gas, 43% proved developed and had a reserve life index of over 20 years, based on 2009 production of 8,808 MMcfe. In addition to our producing wells, we had identified 1,311 total drilling locations in Ozona Northeast, Cinco Terry and North Bald Prairie at December 31, 2009, of which 385 are proved.

Our average realized price for natural gas, oil and NGLs (before the effect of commodity derivatives transactions) decreased 55.4%, 41.4% and 37.7%, respectively, from 2008 to 2009. As a result, we reduced capital expenditures and drilling activity, paid down long-term debt and increased our liquidity by over 40%, from $60.5 million at December 31, 2008 to $85.4 million at December 31, 2009. We define liquidity as funds available under our credit facility plus year-end cash and cash equivalents. At December 31, 2009, we had $32.3 million in long-term debt outstanding under our revolving credit facility, compared to $43.5 million at December 31, 2008. Another result of reduced drilling activity, plus the natural decline of our tight gas fields, was a decline in our average daily production. Average daily production declined from 28.1 MMcfe/d for the three months ended March 31, 2009, to 21.6 MMcfe/d for the three months ended December 31, 2009.

We resumed drilling during September 2009 and currently are operating two rigs in Cinco Terry and one rig in Ozona Northeast. Also in the fourth quarter of 2009, we began acquiring 3-D seismic data across 128.4 square miles, or 82,176 acres, in our Cinco Terry field. We completed the acquisition of 3-D seismic data across our Cinco Terry field in February 2010. Our 3-D seismic data inventory now covers over 135,000 acres in the Permian Basin. Interpretation of the data is expected to be complete by June 2010.

We realize higher oil and NGL volumes in Cinco Terry than in Ozona Northeast (where we have a sales contract that does not include processing of NGLs) or North Bald Prairie (where substantially all of our production is dry gas). Therefore, as we have continued to develop Cinco Terry, we have increased the oil and NGL component of our overall production and reserves. In addition, our contract in Ozona Northeast expires in the first quarter of 2011, after which time we expect to begin processing NGLs in Ozona Northeast. Excluding the effect of any future acquisitions, we expect that further development of Cinco Terry in 2010 and beyond, along with processing gas in Ozona Northeast in 2011 and beyond, will continue to increase the oil and NGL component of our production and reserve in the future.

Segment reporting is not applicable to us as we have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our financial results depend upon many factors, particularly the price of oil and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, estimates of inventory storage levels, gas price differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. A substantial or extended decline in oil and gas prices could have a material adverse effect on our business, financial condition, results of operations, quantities of oil and gas reserves that may be economically produced and liquidity that may be accessed through our borrowing base under our revolving credit facility and through capital markets.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. Future finding and development costs are subject to changes in the industry, including the costs of acquiring, drilling and completing our projects. We focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations will depend on our ability to manage our overall cost structure.

Like all oil and gas production companies, we face the challenge of natural production declines. Oil and gas production from a given well naturally decreases over time. Additionally, our reserves have a rapid initial decline. We attempt to overcome this natural decline by drilling to develop and identify additional reserves, farm-ins or other joint drilling ventures, and by acquisitions. However, during times of severe price declines, we may from time to time reduce current capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially reduce our production volumes and revenues from pre-2009 levels and increase future expected costs necessary to develop existing reserves. As discussed above, due to the extended decline of oil and natural gas prices, we released our remaining rigs during the first week of April 2009. The natural decline of our tight gas fields and reduced drilling activity has caused a decline in our average daily production since the three months ended March 31, 2009.

We also face the challenge of financing future acquisitions. We believe we have adequate unused borrowing capacity under our revolving credit facility for possible acquisitions, temporary working capital needs and any expansion of our drilling program. Funding for future acquisitions also may require additional sources of financing, which may not be available.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting policies generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under GAAP. We also describe the most significant estimates and assumptions we make in applying these policies. See Note 1 to our consolidated financial statements.

Oil and Gas Activities — Successful Efforts

Accounting for oil and gas activities is subject to special, unique rules. We use the successful efforts method of accounting for our oil and gas activities. The significant principles for this method are:

- geological and geophysical evaluation costs are expensed as incurred;
- dry holes for exploratory wells are expensed, and dry holes for developmental wells are capitalized; and
- capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2009, 2008 or 2007.

Proved Reserves

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting*, approving revisions designed to modernize oil and gas reserve reporting requirements. The new reserve rules are effective for our financial statements for the year ended December 31, 2009 and our 2009 year-end proved reserve estimates. The most significant revisions to the reporting requirements include:

- *Commodity prices.* Economic producibility of reserves is now based on the unweighted, arithmetic average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, unless prices are defined by contractual arrangements;
- *Undeveloped oil and gas reserves.* Reserves may be classified as "proved undeveloped" for undrilled areas beyond one offsetting drilling unit from a producing well if there is reasonable certainty that the quantities will be recovered;
- *Reliable technology.* The rules now permit the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;
- *Unproved reserves.* Probable and possible reserves may be disclosed separately on a voluntary basis;
- *Preparation of reserves estimates.* Disclosure is required regarding the internal controls used to assure objectivity in the reserves estimation process and the qualifications of the technical person primarily responsible for preparing reserves estimates; and
- *Third party reports.* We are now required to file the report of any third party used to prepare or audit reserves our estimates.

In addition, in January 2010, FASB issued Account Standards Update, or the Update, 2010-03, "Oil and Gas Reserve Estimation and Disclosures," to provide consistency with the new reserve rules. The Update amends existing standards to align the reserves calculation and disclosure requirements under GAAP with the requirements in the SEC's reserve rules. We adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate.

For the year ended December 31, 2009, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties in accordance with guidelines established by the SEC, including the recent revisions designed to modernize oil and gas reserve reporting requirements. We adopted these revisions effective December 31, 2009.

Estimates of proved oil and gas reserves directly impact financial accounting estimates including depletion, depreciation and amortization expense, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2009, were estimated based on the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2009 for natural gas, oil and NGLs in accordance with new reserve rules.

The new reserve rules resulted in the use of lower prices for natural gas, oil and NGLs than would have resulted under the previous reporting requirements. Under the new reserve rules, our estimated proved reserves increased by 7,860 MMcfe. Under the previous reserve rules, our estimated total proved reserves of natural gas, oil and NGLs would have increased by 20,122 MMcfe. Therefore, the effect of the new reserve rules was a negative revision of 12,262 MMcfe.

Changes in commodity prices and operation costs may also affect the overall evaluation of reservoirs. A hypothetical 10% decline in our December 31, 2009 estimated proved reserves would have increased our depletion expense by approximately $625,000 for the year ended December 31, 2009. Under previous reserve rules (year-end 2009 spot prices for natural gas, oil and NGLs), our depletion expense would have decreased by approximately $400,000.

See also Items 1 and 2. "Business and Properties — Proved Oil and Gas Reserves" and Note 12 to our consolidated financial statements for additional information regarding our estimated proved reserves.

Derivative Instruments and Commodity Derivative Activities

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the collar contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

Changes in the derivative's fair value are currently recognized in the statement of operations unless specific commodity derivative hedge accounting criteria are met and such strategies are designated. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive (loss) income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in accumulated other comprehensive (loss) income are reclassified to oil and gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized (loss) gain on commodity derivatives."

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our oil and gas production. Accordingly, we record realized gains and losses under those instruments in other revenues on our consolidated statements of operations. For the years ended December 31, 2009 and 2007, we recognized an unrealized loss of $9.9 million and $3.6 million, respectively, from the change in the fair value of commodity derivatives. For the year ended December 31, 2008, we recognized an unrealized gain of $7.1 million from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $2.7 million decrease in the December 31, 2009 fair value recorded on our balance sheet, and a corresponding increase to the loss on commodity derivatives in our statement of operations.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation.

Share-Based Compensation

Our 2007 Stock Incentive Plan allows grants of stock and options to employees and outside directors. Granting of awards may increase our general and administrative expenses subject to the size and timing of the grants. See Note 5 to our consolidated financial statements.

We measure and record compensation expense for all share-based payment awards to employees and outside directors based on estimated grant-date fair values. Compensation costs for awards granted are recognized over the requisite service period based on the grant-date fair value.

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the years ended December 31, 2008 and 2007. There were no stock option grants during the year ended December 31, 2009.

	2008	2007
Expected dividends	—	—
Expected volatility	64%	68%
Risk-free interest rate	2.7%	3.9%
Expected life	6 years	6 years

We have not paid out dividends historically, thus the dividend yields are estimated at zero percent.

Since our shares were not publicly traded prior to our initial public offering on November 8, 2007, we used an average of historical volatility rates based upon other companies within our industry. Management believes that these average historical volatility rates are currently the best available indicator of expected volatility.

The risk-free interest rate is the implied yield available for zero-coupon U.S. government issues with a remaining term of five years.

The expected lives of our options are determined based on the term of the option using the simplified method outlined in Staff Accounting Bulletin 110.

Assumptions are reviewed each time there is a new grant and may be impacted by actual fluctuation in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for the options granted or modified and impacts the amount of compensation expense recognized on the consolidated statement of operations.

Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board, or the FASB, issued amendments to Fair Value Measurements and Disclosures under ASC 820-10. Effective for the year ended December 31, 2010, this guidance provides for disclosures of significant transfers in an out of Levels 1 and 2. In addition, the guidance clarifies existing disclosure requirements regarding inputs and valuation techniques as well as the appropriate level of disaggregation for fair value measurements and disclosures. Effective for the year ending December 31, 2011, this guidance provides for disclosures of activity on a gross basis within Level 3 reconciliation. We do not expect this standard to have a significant impact on our financial position or results of operations.

Effects of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2009, 2008 or 2007. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the cost of labor or supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher prices.

Results of Operations

Years Ended December 31, 2009 and 2008

The following table sets forth summary information regarding natural gas, oil and NGL revenues, production, average product prices and average production costs and expenses for the last two years. Oil and NGLs are converted at the rate of one Bbl equals six Mcf.

	Years Ended December 31,	
	2009	**2008**
Revenues (in thousands)		
Gas	$23,406	$58,819
Oil	11,323	16,413
NGLs	5,919	4,637
Total oil and gas sales	40,648	79,869
Realized gain on commodity derivatives	14,659	2,936
Total oil and gas sales including derivative impact	$55,307	$82,805
Production		
Gas (MMcf)	6,320	7,092
Oil (MBbls)	206	175
NGLs (MBbls)	209	102
Total (MMcfe)	8,808	8,755
Total (MMcfe/d)	24.1	23.9
Average prices		
Gas (per Mcf)	$ 3.70	$ 8.29
Oil (per Bbl)	54.97	93.79
NGLs (per Bbl)	28.32	45.46
Total (per Mcfe)	$ 4.61	$ 9.12
Realized gain on commodity derivatives (per Mcfe)	1.66	0.34
Total including derivative impact (per Mcfe)	$ 6.27	$ 9.46
Costs and expenses (per Mcfe)		
Lease operating(1)	$ 0.88	$ 0.87
Severance and production taxes	0.23	0.48
Exploration	0.18	0.17
Impairment of unproved properties	0.34	0.73
General and administrative	1.21	1.01
Depletion, depreciation and amortization	2.80	2.71

(1) Lease operating expenses per Mcfe includes ad valorem taxes.

Oil and gas production. Production for the year ended December 31, 2009 totaled 8.8 Bcfe (24.1 MMcfe/d), compared to 8.8 Bcfe (23.9 MMcfe/d) produced in the prior year. Production for the year ended December 31, 2009 was 72% natural gas and 28% oil and NGLs, compared to 81% natural gas and 19% oil and NGLs in prior year period. We expect production to increase slightly in 2010.

Oil and gas sales. Oil and gas sales decreased $39.2 million, or 49.2%, for the year ended December 31, 2009 to $40.6 million from $79.9 million for the year ended December 31, 2008. The decrease in oil and gas sales principally resulted from sharp decreases in the price we received for our natural gas, oil and NGL production. The average price we received for our production, before the effect of commodity derivatives, decreased from $9.12 per Mcfe to $4.61 per Mcfe, or a 49.5% decrease. Of the $39.2 million decrease in revenues, approximately $41.1 million was attributable to a decrease in oil and gas prices, partially offset by $1.9 million in revenues attributable to a slight increase in production volumes over the prior year.

Commodity derivative activities. Realized losses and gains from our commodity derivative activity increased our earnings by $14.7 million and $2.9 million for the years ended December 31, 2009 and 2008, respectively. Realized gains and losses are derived from the relative movement of gas prices in relation to the range of prices in our collars or the fixed notional pricing for the respective years. The unrealized loss on commodity derivatives was $9.9 million for 2009 and the unrealized gain on commodity derivatives was $7.1 million for 2008. As natural gas commodity prices increase, the fair value of the open portion of those positions decreases. The unrealized loss for 2009 primarily resulted from the settlement of derivative contracts which were outstanding at December 31, 2008. As natural gas commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized (loss) gain on commodity derivatives."

Lease operating expense. Our lease operating expenses, or LOE, increased $156,000, or 2%, for the year ended December 31, 2009 to $7.8 million ($0.88 per Mcfe) from $7.6 million ($0.87 per Mcfe) for the year ended December 31, 2008. Increases in ad valorem taxes and pumpers and supervision costs were partially offset by decreases in well repair and maintenance and workover costs. On a per Mcfe basis, we expect LOE to remain relatively constant in 2010. Following is a summary of lease operating expenses (per Mcfe):

	2009	2008	Change	% Change
Compressor rental and repair	$0.29	$0.28	$ 0.01	3.6%
Pumpers and supervision	0.17	0.14	0.03	21.4
Ad valorem taxes	0.18	0.15	0.03	20.0
Well repair and maintenance	0.09	0.13	(0.04)	(30.8)
Water hauling, insurance and other	0.14	0.13	0.01	7.7
Workovers	0.01	0.04	(0.03)	(75.0)
Total	$0.88	$0.87	$ 0.01	1.1%

Severance and production taxes. Our production taxes decreased $2.2 million, or 52.5%, for the year ended December 31, 2009 to $2 million from $4.2 million for the year ended December 31, 2008. The decrease in production taxes was a function of the decrease in oil and gas sales between 2009 and 2008. Severance and production taxes amounted to approximately 4.9% and 5.3% of oil and gas sales for December 31, 2009 and 2008, respectively. We expect severance and production taxes to be between 5% and 6% of revenues during 2010.

Exploration. We recorded $1.6 million of exploration expense for the year ended December 31, 2009, compared to $1.5 million for the year ended December 31, 2008. Exploration expense in the 2009 period resulted primarily from 3-D seismic acquired across our Cinco Terry field and the expiration of leases in our Ozona Northeast and North Bald Prairie fields. Exploration expense for the 2008 period resulted from one dry hole drilled in Ozona Northeast and $965,000 of lease extensions in Ozona Northeast. Due to additional 3-D expenses from the seismic acquisition across Cinco Terry, lease renewals and expirations, and potential exploration costs in Northern New Mexico, we expect exploration expense to increase in 2010.

Impairment of oil and gas properties. We review our long-lived assets to be held and used, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets, we recorded an impairment of unproved oil and gas properties of $3 million and $6.4 million in 2009 and 2008, respectively. The 2009 impairment resulted from a write-off of $3 million in acreage costs in Northeast British Columbia, and represents the remaining carrying value we have recorded for the project. The 2008 impairment resulted from a write-off of $2.3 million of drilling costs incurred for three test wells in our Boomerang project and $4.1 related to the drilling and completion of three wells in our Northeast British Columbia project.

General and administrative. Our general and administrative expenses, or G&A, increased $1.7 million, or 19.5%, to $10.6 million ($1.21 per Mcfe) for the year ended December 31, 2009 from $8.9 million ($1.01 per Mcfe) for the year ended December 31, 2008. Our G&A for 2009 included higher share-based compensation, as well as higher salaries, related employee benefit costs attributable to an increase in staff from the prior year period and a severance payment to a former officer. Our G&A for the year ended December 31, 2009, also included an increase in franchise taxes. On an absolute basis, we expect G&A to remain relatively constant in 2010. Following is a summary of G&A (in millions and per Mcfe):

	2009		2008		Change		% Change
	$MM	Mcfe	$MM	Mcfe	$MM	Mcfe	per Mcfe
Salaries and benefits	$ 4.9	$0.56	$4.0	$0.45	$ 0.9	$ 0.11	24.4%
Share-based compensation	1.8	0.21	1.1	0.13	0.7	0.08	61.5
Professional fees	1.4	0.16	1.4	0.16	—	—	—
Data processing	0.6	0.07	0.2	0.03	0.4	0.04	133.3
Cash incentive compensation	0.5	0.05	1.0	0.11	(0.5)	(0.06)	(54.5)
Rent expense	0.5	0.06	0.3	0.03	0.2	0.03	100.0
State franchise taxes	0.4	0.04	—	—	0.4	0.04	100.0
Other	0.5	0.06	0.9	0.10	(0.4)	(0.04)	(40.0)
Total	$10.6	$1.21	$8.9	$1.01	$ 1.7	$ 0.20	19.8%

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expense, or DD&A, increased $950,000, or 4%, to $24.7 million for the year ended December 31, 2009 from $23.7 million for the year ended December 31, 2008. Our DD&A per Mcfe increased by $0.09, or 3.3%, to $2.80 per Mcfe for the year ended December 31, 2009, compared to $2.71 per Mcfe for the year ended December 31, 2008. The increase in DD&A was primarily attributable to an increase in oil and gas property costs, partially offset by an increase in estimated proved oil and gas reserves.

Interest expense, net. Our interest expense increased $518,000, or 40.8%, to $1.8 million for the year ended December 31, 2009 from $1.3 million for the year ended December 31, 2008. This increase was substantially the result of our higher average debt level during 2009.

Income taxes. Our provision for income taxes decreased to a benefit of $785,000 for the year ended December 31, 2009, compared with expense of $12.1 million for the year ended December 31, 2008. Our effective income tax rate for the year ended December 31, 2009 was 13.1%, compared with 34.1% for the year ended December 31, 2008. The decrease in the effective rate resulted primarily from a change in our estimated income tax expenses for the year ended December 31, 2008, along with an increased impact of permanent differences between book and taxable income and increased effective state income tax rates.

Years Ended December 31, 2008 and 2007

The following table sets forth summary information regarding natural gas, oil and NGL revenues, production, average product prices and average production costs and expenses for the year ended December 31, 2008 and 2007. Oil and NGLs are converted at the rate of one Bbl equals six Mcf.

	Years Ended December 31,	
	2008	**2007**
Revenues (in thousands)		
Gas	$58,819	$33,497
Oil	16,413	5,062
NGLs	4,637	555
Total oil and gas sales	79,869	39,114
Realized gain on commodity derivatives	2,936	4,732
Total oil and gas sales including derivative impact	$82,805	$43,846
Production		
Gas (MMcf)	7,092	4,801
Oil (MBbls)	175	72
NGLs (MBbls)	102	12
Total (MMcfe)	8,755	5,305
Total (MMcfe/d)	23.9	14.5
Average prices		
Gas (per Mcf)	$ 8.29	$ 6.98
Oil (per Bbl)	93.79	70.31
NGLs (per Bbl)	45.46	46.25
Total (per Mcfe)	$ 9.12	$ 7.37
Realized gain on commodity derivatives (per Mcfe)	0.34	0.89
Total including derivative impact (per Mcfe)	$ 9.46	$ 8.26
Costs and expenses (per Mcfe)		
Lease operating(1)	$ 0.87	$ 0.72
Severance and production taxes	0.48	0.31
Exploration	0.17	0.17
Impairment of unproved properties	0.73	0.05
General and administrative	1.01	2.39
Depletion, depreciation and amortization	2.71	2.47

(1) Lease operating expenses per Mcfe includes ad valorem taxes.

Oil and gas production. Production for the year ended December 31, 2008 totaled 8.7 Bcfe (23.9 MMcfe/d), compared to 5.3 Bcfe (14.5 MMcfe/d) produced in the prior year, an increase of 65%. Production for the year ended December 31, 2008 was 81% natural gas and 19% oil and NGLs, compared to 90% natural gas and 10% oil and NGLs in prior year period.

Oil and gas sales. Oil and gas sales increased $40.8 million, or 104.2%, for the year ended December 31, 2008 to $79.9 million from $39.1 million for the year ended December 31, 2007. The increase in oil and gas sales principally resulted from our increased ownership in the Ozona Northeast field as a result of our acquisition of the Neo Canyon interest in the fourth quarter of 2007 and increased revenue from our Cinco Terry and North Bald Prairie fields. We now own substantially all working interests in Ozona Northeast. Of the 8,755 MMcfe of production reported for 2008, approximately 1,791 MMcfe was attributable to the interest acquired from Neo Canyon. The increase in oil and gas sales also resulted from continued development of our Cinco Terry and North Bald Prairie fields. Cinco Terry production increased by 2,097 MMcfe compared to the prior year. Production from North Bald Prairie accounted for 447 MMcfe in production for 2008. Further, the average price per Mcfe we received for our production increased from $7.37 to $9.12 per Mcfe as average oil and gas prices increased significantly between the two years. Of the $40.8 million increase in revenues, $32.8 million was attributable to growth in volume with the remaining $8 million due to oil and gas price increases. Natural gas sales represented 73.6% of the total oil and gas sales in 2008 compared to 85.6% in 2007, as our Cinco Terry field has a larger component of oil and NGLs in its production.

Commodity derivative activities. Realized losses and gains from our commodity derivative activity increased our earnings by $2.9 million and $4.7 million for the years ended December 31, 2008 and 2007, respectively. Realized gains and losses are derived from the relative movement of gas prices in relation to the range of prices in our collars or the fixed notional pricing for the respective years. The unrealized gain on commodity derivatives was $7.1 million for 2008 and the unrealized loss on commodity derivatives was $3.6 million for 2007. As natural gas commodity prices increase, the fair value of the open portion of those positions decreases. As natural gas commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized (loss) gain on commodity derivatives."

Lease operating expense. Our LOE increased $3.8 million, or 99.8%, for the year ended December 31, 2008 to $7.6 million ($0.87 per Mcfe) from $3.8 million ($0.72 per Mcfe) for the year ended December 31, 2007. The increase in LOE over the prior year was primarily a result of the acquisition of the Neo Canyon 30% working interest and Strawn/Ellenburger deep rights in Ozona Northeast. The increase in 2008 was also attributable to initial startup costs, including compression and treating costs in Cinco Terry and North Bald Prairie, as well as a rise in repair and maintenance costs in Ozona Northeast. Following is a summary of lease operating expenses (per Mcfe):

	2008	2007	Change	% Change
Compressor rental and repair	$0.28	$0.18	$ 0.10	55.6%
Pumpers and supervision	0.15	0.10	0.05	50.0
Ad valorem taxes	0.14	0.18	(0.04)	(22.2)
Repairs and maintenance	0.13	0.07	0.06	85.7
Water hauling, insurance and other	0.13	0.12	0.01	8.3
Workovers	0.04	0.07	(0.03)	(42.9)
Total	$0.87	$0.72	$ 0.15	20.8%

Severance and production taxes. Our production taxes increased $2.5 million, or 153.3%, for the year ended December 31, 2008 to $4.2 million from $1.7 million for the year ended December 31, 2007. The increase in production taxes was a function of the increase in oil and gas sales between the two periods. Severance and productions taxes amounted to approximately 5.3% and 4.2% of oil and gas sales for the respective years. The increase in the severance and production taxes as a percentage of oil and gas sales is due to higher severance tax rates for NGL revenues from Cinco Terry and higher estimated taxes after abatements for newer wells in Ozona Northeast and Cinco Terry.

Exploration. We recorded $1.5 million of exploration expense for the year ended December 31, 2008, compared to $883,000 for the year ended December 31, 2007. Exploration expense for the 2008 period resulted from one dry hole drilled in Ozona Northeast and $965,000 of lease extensions in Ozona Northeast. We incur these costs to maintain our leasehold positions and accordingly, we expense them as incurred. Exploration expense for the 2007 period resulted from the drilling of two dry holes in our Boomerang project and Cinco Terry project.

Impairment of oil and gas properties. We review our long-lived assets to be held and used, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting.

As a result of this review of the recoverability of the carrying value of our assets, we recorded an impairment of oil and gas properties of $6.4 million and $267,000 in 2008 and 2007, respectively. The 2008 impairment resulted from a write-off of $2.3 million of drilling costs incurred for three test wells in our Boomerang project and $4.1 related to the drilling and completion of three wells in our Northeast British Columbia project. The 2007 impairment resulted from the abandonment of an expiring leasehold position in Ozona Northeast covering 2,282 acres.

General and administrative. Our G&A decreased $3.8 million, or 29.9%, to $8.9 million ($1.01 per Mcfe) for the year ended December 31, 2008 from $12.7 million ($2.39 per Mcfe) for the year ended December 31, 2007. Our G&A for 2007 included $4.6 million in non-cash, share-based compensation (of which $3.9 million was related to the IPO), $2.4 million in cash incentive compensation to cover out-of-pocket taxes related to IPO stock awards, $1 million of cash incentive compensation related to the IPO and $0.7 million in cash incentive compensation to cover out-of-pocket taxes related to management's exchange of common stock in 2007 to repay full recourse management notes before the IPO. Partially offsetting the higher expenses in 2007 was an increase in G&A in 2008 attributable to increased salaries and benefits of $2 million related to an increase in staff, professional fees of $900,000, share-based compensation of $1.1 million and cash incentive compensation of $967,000. Additionally, the 2007 period includes a severance obligation of $350,000 related to a former employee. Following is a summary of G&A (in millions and per Mcfe):

	2008		2007		Change		% Change
	$MM	Mcfe	$MM	per Mcfe	$MM	Mcfe	per Mcfe
Salaries and benefits	$4.0	$0.45	$ 2.8	$0.54	$ 1.2	$(0.09)	(16.7)%
Professional fees	1.4	0.16	0.5	0.10	0.9	0.06	60.0
Share-based compensation	1.1	0.13	4.6	0.87	(3.5)	(0.74)	(85.1)
Cash incentive compensation	1.0	0.11	4.1	0.77	(3.1)	(0.66)	(85.7)
Other	1.4	0.16	0.7	0.11	0.7	0.05	45.5
Total	$8.9	$1.01	$12.7	$2.39	$(3.8)	$(1.38)	(57.7)%

Depletion, depreciation and amortization. Our DD&A increased $10.6 million, or 81%, to $23.7 million for the year ended December 31, 2008 from $13.1 million for the year ended December 31, 2007. Our DD&A per Mcfe increased by $0.24, or 9.7%, to $2.71 per Mcfe for the year ended December 31, 2008, compared to $2.47 per Mcfe for the year ended December 31, 2007. The increase in DD&A was primarily attributable to increased production and higher capital costs, partially offset by an increase in our estimated proved reserves at December 31, 2008. The higher DD&A per Mcfe was primarily attributable to higher capital costs incurred in North Bald Prairie and reserve revisions in Ozona Northeast at December 31, 2007. In North Bald Prairie, we paid capital costs attributable to the 50% working interest owned by our working interest partner pursuant to our carry and earning agreement on the first five wells drilled.

Interest expense, net. Our interest expense decreased $4 million, or 75.7%, to $1.3 million for the year ended December 31, 2008 from $5.2 million for the year ended December 31, 2007. This decrease was substantially the result of our lower average debt level and lower interest rates in 2008. Additionally, interest expense for the year ended December 31, 2007 included $1.5 million related to the beneficial conversion feature of our convertible notes and $548,000 relating to accrued interest on the convertible notes.

Income taxes. Our provision for income taxes increased to $12.1 million for the year ended December 31, 2008, from a benefit of $108,000 for the year ended December 31, 2007. The increase in income tax expense was due to the increase in our income before income taxes. Our effective income tax rate for the year ended December 31, 2008 was 34.1%, compared with a benefit of 4.2% for the year ended December 31, 2007. The tax benefit for the year ended December 31, 2007 related to the release of a valuation allowance on net operating loss carryovers generated by AOG before the combination of AOG and Approach under the Contribution Agreement on November 14, 2007.

Liquidity and Capital Resources

We generally will rely on cash generated from operations, borrowings under our revolving credit facility and, to the extent that credit and capital market conditions will allow, future public equity and debt offerings to satisfy our liquidity needs. Our ability to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, availability of borrowings under our revolving credit facility, and more broadly, on the availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot predict whether additional liquidity from equity or debt financings beyond our revolving credit facility will be available on acceptable terms, or at all, in the foreseeable future.

Our cash flow from operations is driven by commodity prices and production volumes and the effect of commodity derivatives. Prices for oil and gas are affected by national and international economic and political environments, national and global supply and demand for hydrocarbons, seasonal influences of weather and other factors beyond our control. Our working capital is significantly influenced by changes in commodity prices, and significant declines in prices will cause a decrease in our production volumes and exploration and development expenditures. Our working capital also is influenced by our efforts to lower our long-term debt and related interest costs. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

We intend to fund 2010 capital expenditures, excluding any acquisitions, primarily out of internally-generated cash flows and, as necessary, borrowings under our revolving credit facility. As of December 31, 2009, we had $82.3 million available to borrow under our revolving credit facility.

For the year ended December 31, 2009, our primary sources of cash were from operating activities. Approximately $39.8 million of cash from operations was used to fund our drilling program and 3-D seismic operations and pay down our long-term debt.

For the year ended December 31, 2008, our primary sources of cash were from financing and operating activities. Approximately $43.5 million from borrowings (net of payments) under our revolving credit facility and $56.4 million cash from operations were used to fund our drilling program and the acquisition of a 95% working interest below the top of the Strawn formation and rights to 75 miles of gathering system in the Ozona Northeast field.

Our primary sources of cash in 2007 were from financing and operating activities. Approximately $64.3 million from borrowings under our revolving credit facility, $72.4 million from the issuance of common stock, $20 million from proceeds from convertible notes and $30.7 million cash from operations were used to fund our drilling activities, repay our revolving credit facility and purchase 2,021,148 shares of our common stock from the selling stockholder in our IPO.

In comparing 2009 and 2008, our cash flows from operations decreased in 2009 due mostly to lower oil and gas sales partially offset by an increase in other cash income and expense items and a decrease in working capital components during the year ended December 31, 2009. In comparing 2008 and 2007, our cash flows from operations increased in 2008 due mostly to higher oil and gas sales partially offset by an increase in most operating expense categories and a decrease in working capital components during the year ended December 31, 2008.

The following table summarizes our sources and uses of funds for the periods noted:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows provided by operating activities	$ 39,761	$ 56,435	$ 30,746
Cash flows used in investing activities	(29,553)	(100,633)	(52,940)
Cash flows (used in) provided by financing activities	(11,618)	43,696	22,062
Effect of Canadian exchange rate	18	(206)	6
Net decrease in cash and cash equivalents	$ (1,392)	$ (708)	$ (126)

Despite the adverse price environment in 2009, we were able to pay down our long-term debt and increase our liquidity by over 40%, from $60.5 million at December 31, 2008 to $85.4 million at December 31, 2009. We define liquidity as funds available under our credit facility plus year-end cash and cash equivalents. At December 31, 2009, we had $32.3 million in long-term debt outstanding under our revolving credit facility, compared to $43.5 million in long-term debt outstanding at December 31, 2008. The following table summarizes our liquidity position at December 31, 2009 compared to December 31, 2008:

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Borrowing base	$115,000	$100,000
Cash and cash equivalents	2,685	4,077
Long-term debt	(32,319)	(43,537)
Liquidity	$ 85,366	$ 60,540

Operating Activities

For the year ended December 31, 2009, our cash flow from operations, borrowings under our revolving credit facility and available cash were used for drilling activities, 3-D seismic operations and for the payment of a portion of our long-term debt. The $39.8 million in cash flows generated in the 2009 period decreased $16.7 million from the same period in 2008 due primarily to a $39.2 million decline in oil and gas sales, partially offset by a $10 million decrease in working capital components and a net increase of $12.5 million in other cash income and expense items.

For the year ended December 31, 2008, our cash flow from operations, borrowings under our revolving credit facility and available cash were used for drilling activities. The $56.4 million in cash flow generated during 2008 period increased by $25.7 million from 2007 due primarily to an increase in oil and gas sales and a decrease in general and administrative expenses. Partially offsetting the increase in oil and gas sales and decrease in general administrative expenses was a reduction in working capital and an increase in LOE and production taxes in the 2008 period compared to the 2007 period.

For the year ended December 31, 2007, our cash flow from operations was used for drilling activities. The $30.7 million in cash flow generated during 2007 decreased $3.6 million from 2006 due mostly to lower oil and gas sales and higher general and administrative expenses in the 2007 period.

Investing Activities

The majority of our cash flows used in investing activities for the years ended 2009, 2008 and 2007 have been used for the continued development of the Ozona Northeast, Cinco Terry and North Bald Prairie fields. The following is a summary of capital expenditures related to our oil and gas properties:

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Ozona Northeast	$ 5,768	$ 31,362	$27,986
Ozona Northeast deep rights acquisition	—	10,346	—
Cinco Terry	20,630	32,363	10,586
North Bald Prairie	1,554	15,871	4,974
El Vado East	151	176	—
Boomerang	—	290	2,496
Inventory	(1,959)	2,365	—
Northeast British Columbia	86	2,993	1,235
Lease acquisition, geological, geophysical and other	2,760	4,323	4,920
Total	$28,990	$100,089	$52,197

Lease acquisition, geological, geophysical and other for the year ended December 31, 2009 includes:

- $1.1 million of leasehold acquisitions related to Cinco Terry;
- $915,000 of 3-D seismic acquisition related to Cinco Terry; and
- $500,000 of leasehold acquisitions related to North Bald Prairie during the year ended December 31, 2009.

Lease acquisition, geological, geophysical and other for the year ended December 31, 2008 includes:

- $1.9 million of leasehold acquisitions related to Ozona Northeast; and
- $2 million of leasehold acquisitions related to Cinco Terry during the year ended December 31, 2008.

Lease acquisition, geological, geophysical and other for the year ended December 31, 2007 includes:

- $3 million for undeveloped leaseholds in our Northeast British Columbia prospect; and
- $2.5 million for undeveloped leaseholds in our El Vado East prospect during the year ended December 31, 2007.

Financing Activities

We borrowed $67.4 million under our revolving credit facility in 2009 compared to $121.7 million in 2008 and $64.3 million in 2007. We repaid a total of $78.6 million, $78.2 million and $111.9 million of amounts outstanding under our revolving credit facility for the years ended December 31, 2009, 2008 and 2007, respectively. In 2007, we borrowed $20 million by issuing convertible notes. These notes were converted to outstanding shares of our common stock in connection with our IPO in November 2007.

In 2007, and in connection with our IPO and exercise by the underwriters of their overallotment option, we sold 6,598,572 shares of our common stock in November 2007 at $12 per share. The gross proceeds of our IPO and over-allotment option were approximately $79.2 million, which resulted in net proceeds to the Company of $73.6 million after deducting underwriter discounts and commissions of approximately $5.6 million. The aggregate net proceeds of approximately $73.6 million received by the Company were used as follows (in millions):

Repayment of revolving credit facility	$51.1
Repurchase of stock held by selling stockholder	$22.5

Our current goal is to manage our borrowings to help us maintain financial flexibility and liquidity, and to avoid the problems associated with highly-leveraged companies with large interest costs and possible debt reductions restricting ongoing operations.

We believe that cash flows from operations and borrowings under our revolving credit facility will finance substantially all of our capital needs through 2010. We may also use our revolving credit facility for possible acquisitions and temporary working capital needs. Further, we may determine to access the public equity or debt markets for potential acquisitions, working capital or other liquidity needs, if such financing is available on acceptable terms. In January 2010, we filed a "shelf" registration statement on Form S-3 registering up to $150 million of common stock, debt and other securities. The registration statement was declared effective by the SEC on February 1, 2010.

2010 Capital Expenditures

The following table summarizes our estimated capital expenditures for 2010. We intend to fund 2010 capital expenditures, excluding any acquisitions, primarily out of internally-generated cash flows and, as necessary, borrowings under our revolving credit facility.

	Year Ending December 31, 2010
	(In thousands)
West Texas	
Ozona Northeast	$25,600
Cinco Terry	19,950
Exploratory	3,075
Lease acquisition, geological and geophysical	4,375
Total capital expenditures	$53,000

Our capital expenditure budget for 2010 is subject to change depending upon a number of factors, including economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our development and exploration efforts, the availability of sufficient capital resources for drilling prospects, our financial results, the availability of leases on reasonable terms and our ability to obtain permits for the drilling locations. We expect drilling rigs, drilling crews, steel tubulars and oilfield services to be in high demand in the Permian Basin during 2010, and that the costs related to these services will increase from 2009 levels.

Revolving Credit Facility

We have a $200 million revolving credit facility with a borrowing base set at $115 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

Currently, the maturity date under our revolving credit facility is July 31, 2011. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of non-used borrowings available under our revolving credit facility.

We had outstanding borrowings of $32.3 million under our revolving credit facility at December 31, 2009. The weighted average interest rate applicable to our outstanding borrowings was 3.20% at December 31, 2009. We also had outstanding unused letters of credit under our revolving credit facility totaling $400,000 at December 31, 2009, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

At February 28, 2010, we had $37.9 million outstanding under our revolving credit facility, with a weighted average interest rate of 3.42%.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.

- a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 3.5 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other non-cash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or non-recurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as more specifically defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At December 31, 2009, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

To date we have experienced no disruptions in our ability to access our revolving credit facility. However, our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors, including the loan collateral value that each lender, in its discretion and using the methodology, assumptions and discount rates as such lender customarily uses in evaluating oil and gas properties, assigns to our properties.

Contractual Commitments

Our contractual commitments consist of long-term debt, accrued interest on long-term debt, daywork drilling contracts, operating lease obligations, asset retirement obligations and employment agreements with executive officers.

Our long-term debt is composed of borrowings under our revolving credit facility. Borrowings based on the agent bank's prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of non-used borrowings available under our revolving credit facility. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Credit Facility" and Note 4 for a discussion of our revolving credit facility.

We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital expenditures are incurred or rig services are provided. Our commitment under the drilling contracts is $1.2 million at December 31, 2009.

In April 2007, we signed a five-year lease for approximately 13,000 square feet of office space in Fort Worth, Texas. In August 2008, we expanded our office space under an amendment to the lease to approximately 18,000 square feet. In January 2009, we began rent payments of approximately $30,000 per month, including common area expenses.

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

We have outstanding employment agreements with two of our executive officers that contain automatic renewal provisions providing that such agreements may be automatically renewed for successive terms of one year unless employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, was approximately $700,000 at December 31, 2009.

The following table summarizes these commitments as of December 31, 2009 (in thousands):

Contractual Obligations	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt(1)	$32,319	$ —	$32,319	$—	$ —
Interest on long-term debt(2)	1,637	1,034	603	—	—
Daywork drilling contracts(3)	1,169	1,169			
Operating lease obligations(4)	1,182	410	772	—	—
Asset retirement obligations(5)	4,597	—	—	—	4,597
Employment agreements with executive officers	700	700	—	—	—
Total	$41,604	$3,313	$33,694	$—	$4,597

(1) See Note 4 to our consolidated financial statements for a discussion of our revolving credit facility.

(2) Interest payments have been calculated by applying the interest rate of 3.20% at December 31, 2009, to the outstanding long-term debt of $32.3 million at December 31, 2009.

(3) Daywork drilling contracts related to three drilling rigs contracted through February 28, 2010.

(4) Operating lease obligations are for office space and equipment.

(5) See Note 1 to our consolidated financial statements for a discussion of our asset retirement obligations.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2009, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit, operating lease agreements and gas transportation commitments. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and gas prices, and other related factors. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for commodity derivative and investment purposes, not for trading purposes.

Proved Reserves

Estimates of proved oil and gas reserves directly impact financial accounting estimates including depletion, depreciation and amortization expense, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2009, were estimated based on the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2009 for natural gas, oil and NGLs, in accordance with new reserve rules.

Changes in commodity prices and operation costs may also affect the overall evaluation of reservoirs. A hypothetical 10% decline in our December 31, 2009 estimated proved reserves would have increased our depletion expense by approximately $625,000 for the year ended December 31, 2009. Under previous reserve rules (year-end 2009 spot prices for natural gas, oil and NGLs), our depletion expense would have decreased by approximately $400,000.

Commodity Price Risk

Given the current economic outlook, we expect commodity prices to remain volatile. Even modest decreases in commodity prices can materially affect our revenues and cash flow. In addition, if commodity prices remain suppressed for a significant amount of time, we could be required under successful efforts accounting rules to perform a write down of our oil and gas properties.

We enter into financial swaps and collars to reduce the risk of commodity price fluctuations. We do not designate such instruments as cash flow hedges. Accordingly, we record open commodity derivative positions on our consolidated balance sheets at fair value and recognize changes in such fair values as income (expense) on our consolidated statements of operations as they occur.

At December 31, 2009, we have the following commodity derivative positions outstanding:

	Volume (MMBtu)		$/MMBtu
Period	Monthly	Total	Fixed
NYMEX — Henry Hub			
Price swaps 2010	150,000	1,800,000	$ 5.85
Price swaps 2010	150,000	1,800,000	$ 6.40
Price swaps 2010	100,000	1,200,000	$ 6.36
WAHA basis differential			
Basis swaps 2010	415,000	4,980,000	$(0.71)
Basis swaps 2011	300,000	3,600,000	$(0.53)

At December 31, 2009 and December 31, 2008, the fair value of our open derivative contracts was a net liability of approximately $1.9 million and an asset of $8 million, respectively.

JPMorgan Chase Bank, National Association and KeyBank National Association are currently the only counterparties to our commodity derivatives positions. We are exposed to credit losses in the event of nonperformance by counterparties on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions. JPMorgan is the administrative agent and a participant, and KeyBank is a participant, in our revolving credit facility and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the collar contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

For the years ended December 31, 2009 and 2007, we recognized an unrealized loss of $9.9 million and $3.6 million, respectively, from the change in the fair value of commodity derivatives. For the year ended December 31, 2008, we recognized an unrealized gain of $7.1 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2009, the unrealized loss on commodity derivatives was primarily attributable to the settlement of derivative contracts. A hypothetical 10% increase in the

NYMEX floating prices would have resulted in a $2.7 million decrease in the December 31, 2009 fair value recorded on our balance sheet, and a corresponding increase to the loss on commodity derivatives in our statement of operations.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that 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 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2009, we had no Level 1 measurements.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2009, all of our commodity derivatives were valued using Level 2 measurements.
- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2009, our Level 3 measurements were used to calculate our asset retirement obligation and our impairment analysis of proved properties at December 31, 2009.

Item 8. *Financial Statements and Supplementary Data.*

See "Index to Financial Statements" on page F-1 of this report.

Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Disclosure Controls and Procedures

Our management, with the participation of our President and Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2009. Based on this evaluation, our President and Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2009, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) accumulated and communicated to our management, including our President and Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of Registered Public Accounting Firm

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management's assessment of the design and effectiveness of our internal controls as part of this annual report on Form 10-K for the fiscal year ended December 31, 2009. Hein & Associates LLP, or Hein, our independent registered public accounting firm, also attested to, and reported on, our internal control over financial reporting. Management's report and Hein's attestation report are referenced on page F-1 under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm — Internal Control over Financial Reporting" and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

No changes to our internal control over financial reporting occurred during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act).

Item 9A(T). ***Controls and Procedures.***

Not applicable.

Item 9B. ***Other Information.***

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

Information required under Item 10, "Directors, Executive Officers and Corporate Governance" will be contained under the captions "Election of Directors — Directors" and "Executive Officers" to be provided in our proxy statement for our 2010 annual meeting of stockholders to be filed with the SEC on or before April 30, 2010, which are incorporated herein by reference. Additional information regarding our corporate governance guidelines as well as the complete texts of our Code of Conduct and the charters of our Audit Committee and our Nominating and Compensation Committee may be found on our website at *www.approachresources.com.*

Item 11. *Executive Compensation.*

Information required by Item 11 of this report will be contained under the caption "Executive Compensation" in our proxy statement for our 2010 annual meeting of stockholders to be filed with the SEC on or before April 30, 2010, which is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Information required by Item 12 of this report will be contained under the caption "Stock Ownership Matters" in our proxy statement for our 2010 annual meeting of stockholders to be filed with the SEC on or before April 30, 2010, which is incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information required by Item 13 of this report will be contained under the captions "Certain Relationships and Related Party Transactions" and "Corporate Governance" in our definitive proxy statement for our 2010 annual meeting of stockholders to be filed with the SEC on or before April 30, 2010, which are incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services.*

Information required by Item 14 of this report will be contained under the caption "Independent Registered Public Accountants" in our definitive proxy statement for our 2010 annual meeting of stockholders to be filed with the SEC on or before April 30, 2010, which is incorporated herein by reference.

PART IV

Item 15. *Exhibits, Financial Statement Schedules.*

(a) Documents Filed as Part of this Report

(1) and (2) Financial Statements and Financial Statement Schedules.

See "Index to Consolidated Financial Statements" on page F-1.

(3) Exhibits.

See "Index to Exhibits" on page 66 for a description of the exhibits filed as part of this report.

GLOSSARY OF SELECTED OIL AND GAS TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this report.

3-D seismic. (Three Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.

Basin. A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

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

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

Completion. The installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

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

Developed oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(6) of Regulation S-X, which defines proved reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered.

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developmental well. A well drilled within the proved boundaries of an oil or gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. An exploratory, development or extension well that proved to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Dry hole costs. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

Exploitation. Ordinarily considered to be a form of development within a known reservoir.

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

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

Fracing or Fracture stimulation technology. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or gases may more easily flow through the formation.

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

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

LNG. Liquefied natural gas.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

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

MMBtu. Million British thermal units.

MMcf. Million cubic feet of gas.

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

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

NGLs. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

Productive well. A, exploratory, development or extension well that is not a dry well.

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

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

Proved oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as follows:

> Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> (i) The area of the reservoir considered as proved includes:
>
> (A) The area identified by drilling and limited by fluid contacts, if any, and
>
> (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
>
> (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's practice, to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of PV-10 are made using oil and gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Reserve life index. This index is calculated by dividing year-end 2009 reserves by 2009 production of 8,808 MMcfe to estimate the number of years of remaining production.

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

Spacing. The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions.

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

Tight gas sands. A formation with low permeability that produces natural gas with low flow rates for long periods of time.

Unconventional resources or reserves. Natural gas or oil resources or reserves from (i) low-permeability sandstone and shale formations, such as tight gas and gas shales, respectively, and (ii) coalbed methane.

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

Undeveloped oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(31) of Regulation S-X, which defines proved undeveloped reserves as follows:

> Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
>
> (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
>
> (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
>
> (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

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

Workover. Operations on a producing well to restore or increase production.

/d. "Per day" when used with volumetric units or dollars.

SIGNATURES

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

APPROACH RESOURCES INC.

By: /s/ J. Ross Craft
J. Ross Craft
President and Chief Executive Officer

Date: March 12, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on March 12, 2010.

Signature	Title
/s/ J. Ross Craft J. Ross Craft	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Steven P. Smart Steven P. Smart	Executive Vice President and Chief Financial Officer (Principal Financial and Principal Accounting Officer)
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director and Chairman of the Board of Directors
/s/ James H. Brandi James H. Brandi	Director
/s/ James C. Crain James C. Crain	Director
/s/ Sheldon B. Lubar Sheldon B. Lubar	Director
/s/ Christopher J. Whyte Christopher J. Whyte	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS OF APPROACH RESOURCES INC.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we believe that, as of December 31, 2009, our internal control over financial reporting is effective based on those criteria.

By: /s/ J. Ross Craft
J. Ross Craft
President and Chief Executive Officer

By: /s/ Steven P. Smart
Steven P. Smart
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
March 12, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.

We have audited Approach Resources Inc. and subsidiaries' (collectively, the "Company") internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that *(a)* pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; *(b)* provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and *(c)* provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Approach Resources Inc. and subsidiaries as of December 31, 2009 and 2008, and the related statements of operations, changes in stockholders' equity, cash flows and comprehensive (loss) income for each of the three years in the period ended December 31, 2009 and our report dated March 12, 2010, expressed an unqualified opinion.

/s/ ***HEIN*** *& ASSOCIATES LLP*
Dallas, Texas
March 12, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.

We have audited the accompanying consolidated balance sheets of Approach Resources Inc. and subsidiaries (collectively, the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in stockholders' equity, cash flows and comprehensive (loss) income for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Approach Resources Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ ***HEIN*** *& ASSOCIATES LLP*
Dallas, Texas
March 12, 2010

Approach Resources Inc. and Subsidiaries

Consolidated Balance Sheets
(In thousands, except shares and per-share amounts)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,685	$ 4,077
Accounts receivable:		
Joint interest owners	3,088	16,228
Oil and gas sales	4,607	5,936
Unrealized gain on commodity derivatives	786	8,017
Prepaid expenses and other current assets	837	579
Total current assets	12,003	34,837
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	387,792	362,805
Furniture, fixtures and equipment	1,540	977
	389,332	363,782
Less accumulated depletion, depreciation and amortization	(84,849)	(60,378)
Net properties and equipment	304,483	303,404
OTHER ASSETS	2,440	—
Total assets	$318,926	$338,241
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Advances from non-operators	$ 2,689	$ —
Accounts payable	3,074	13,564
Oil and gas sales payable	3,774	4,631
Accrued liabilities	10,935	9,810
Current portion of deferred income taxes	—	2,770
Unrealized loss on commodity derivatives	1,524	—
Total current liabilities	21,996	30,775
NON-CURRENT LIABILITIES:		
Long-term debt	32,319	43,537
Unrealized loss on commodity derivatives	1,144	—
Deferred income taxes	38,374	35,891
Asset retirement obligations	4,597	4,225
Total liabilities	98,430	114,428
COMMITMENTS AND CONTINGENCIES (Note 10)		
STOCKHOLDERS' EQUITY :		
Preferred stock, $0.01 par value, 10,000,000 shares authorized none outstanding	—	—
Common stock, $0.01 par value, 90,000,000 shares authorized, 20,959,285 and 20,715,357 issued and outstanding, respectively	209	207
Additional paid-in capital	168,993	167,349
Retained earnings	51,524	56,753
Accumulated other comprehensive loss	(230)	(496)
Total stockholders' equity	220,496	223,813
Total liabilities and stockholders' equity	$318,926	$338,241

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Operations
(In thousands, except shares and per-share amounts)

	Years Ended December 31, 2009	2008	2007
REVENUES:			
Oil and gas sales	$ 40,648	$ 79,869	$ 39,114
EXPENSES:			
Lease operating	7,777	7,621	3,815
Severance and production taxes	1,996	4,202	1,659
Exploration	1,621	1,478	883
Impairment of unproved properties	2,964	6,379	267
General and administrative	10,617	8,881	12,667
Depletion, depreciation and amortization	24,660	23,710	13,098
Total expenses	49,635	52,271	32,389
OPERATING (LOSS) INCOME	(8,987)	27,598	6,725
OTHER:			
Impairment of investment	—	(917)	—
Interest expense, net	(1,787)	(1,269)	(5,219)
Realized gain on commodity derivatives	14,659	2,936	4,732
Unrealized (loss) gain on commodity derivatives	(9,899)	7,149	(3,637)
(LOSS) INCOME BEFORE INCOME TAX (BENEFIT) PROVISION	(6,014)	35,497	2,601
INCOME TAX (BENEFIT) PROVISION	(785)	12,111	(108)
NET (LOSS) INCOME	$ (5,229)	$ 23,386	$ 2,709
(LOSS) EARNINGS PER SHARE:			
Basic	$ (0.25)	$ 1.13	$ 0.25
Diluted	$ (0.25)	$ 1.12	$ 0.24
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	20,869,832	20,647,339	11,036,799
Diluted	20,869,832	20,824,905	11,183,707

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders' Equity for the Years Ended December 31, 2007, 2008 and 2009 (In thousands, except shares and per-share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Loans to Stockholders, Including Accrued Interest	Accumulated Other Comprehensive Income (Loss)	Total
BALANCES, January 1, 2007	9,735,312	97	43,001	30,658	(4,184)	—	69,572
Retirement of loans to stockholders	(253,650)	(2)	(4,182)	—	4,184	—	—
Issuance of common shares to management and directors for compensation	411,041	4	(4)	—	—	—	—
Issuance of stock upon exercise of stock options	72,114	1	239	—	—	—	240
Share-based compensation expense	—	—	4,646	—	—	—	4,646
Issuance of common stock upon conversion of convertible notes	1,841,262	18	20,530	—	—	—	20,548
Beneficial conversion feature of convertible notes	—	—	1,547	—	—	—	1,547
Issuance of shares in initial public offering	6,598,572	66	73,574	—	—	—	73,640
Offering costs related to the initial public offering	—	—	(1,503)	—	—	—	(1,503)
Issuance of shares for acquisition of oil and gas properties	4,239,243	42	50,829	—	—	—	50,871
Purchase and cancellation of common stock	(2,021,148)	(20)	(22,536)	—	—	—	(22,556)
Net income	—	—	—	2,709	—	—	2,709
Foreign currency translation adjustments	—	—	—	—	—	105	105
BALANCES, December 31, 2007	20,622,746	206	166,141	33,367	—	105	199,819
Issuance of stock upon exercise of stock options	63,459	1	212	—	—	—	213
Restricted stock issuance	29,152	—	—	—	—	—	—
Share-based compensation expense	—	—	1,100	—	—	—	1,100
Surrender of restricted shares for payment of income taxes	—	—	(54)	—	—	—	(54)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(50)	—	—	—	(50)
Net income	—	—	—	23,386	—	—	23,386
Foreign currency translation adjustments, net of related income tax of $256	—	—	—	—	—	(601)	(601)
BALANCES, December 31, 2008	20,715,357	$207	$167,349	$56,753	$ —	$(496)	223,813
Issuance of common shares to directors for compensation	50,845	—	378	—	—	—	378
Restricted stock issuance, net of cancellations	202,040	2	(2)	—	—	—	—
Share-based compensation expense	—	—	1,448	—	—	—	1,448
Surrender of restricted shares for payment of income taxes	(8,957)	—	(68)	—	—	—	(68)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(112)	—	—	—	(112)
Net loss	—	—	—	(5,229)	—	—	(5,229)
Foreign currency translation adjustments, net of related income tax of $118	—	—	—	—	—	266	266
BALANCES, December 31, 2009	20,959,285	$209	$168,993	$51,524	—	$(230)	$220,496

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Cash Flows
(In thousands, except shares and per-share amounts)

	For the Years Ended December 31,		
	2009	2008	2007
OPERATING ACTIVITIES:			
Net (loss) income	$ (5,229)	$ 23,386	$ 2,709
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depletion, depreciation and amortization	24,660	23,710	13,098
Non-cash interest expense on convertible notes	—	—	2,095
Unrealized loss (gain) on commodity derivatives	9,899	(7,149)	3,637
Impairment of unproved properties	2,964	6,379	267
Impairment of investment	—	917	—
Exploration expense	1,621	1,478	883
Share-based compensation expense	1,826	1,100	4,646
Deferred income taxes	(785)	12,148	(296)
Changes in operating assets and liabilities:			
Accounts receivable	12,352	(11,501)	(2,657)
Prepaid expenses and other current assets	71	(38)	(232)
Accounts payable	(7,863)	8,105	(787)
Oil and gas sales payable	(857)	2,837	(3,146)
Accrued liabilities	1,102	(4,937)	10,529
Cash provided by operating activities	39,761	56,435	30,746
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(28,990)	(100,089)	(51,845)
Additions to furniture, fixtures and equipment, net	(563)	(544)	(178)
Investments	—	—	(917)
Cash used in investing activities	(29,553)	(100,633)	(52,940)
FINANCING ACTIVITIES:			
Loan origination fees	(400)	—	(140)
Borrowings under credit facility	67,407	121,687	64,285
Repayment of amounts outstanding under credit facility	(78,625)	(78,150)	(111,904)
Proceeds from convertible notes	—	—	20,000
Proceeds from issuance of common stock	—	213	72,377
Surrender of restricted shares for payment of income taxes	—	(54)	—
Purchase of common stock	—	—	(22,556)
Cash (used in) provided by financing activities	(11,618)	43,696	22,062
CHANGE IN CASH AND CASH EQUIVALENTS	(1,410)	(502)	(132)
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	18	(206)	6
CASH AND CASH EQUIVALENTS, beginning of year	4,077	4,785	4,911
CASH AND CASH EQUIVALENTS, end of year	$ 2,685	$ 4,077	$ 4,785
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 1,790	$ 894	$ 4,117
Cash paid for income taxes	$ —	$ 397	$ 1,287
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Acquisition of oil and gas properties	$ —	$ 509	$ 60,225
Asset retirement obligations capitalized	$ 170	$ 3,504	$ 257
Conversion of convertible notes and accrued interest into common stock	$ —	$ —	$ 20,548
Retirement of loans to stockholders in exchange for shares of common stock	$ —	$ —	$ 4,184

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Comprehensive (Loss) Income
(In thousands)

	For the Years Ended December 31,		
	2009	2008	2007
Net (loss) income	$(5,229)	$23,386	$2,709
Other comprehensive (loss) income:			
Foreign currency translation, net of related income tax	266	(601)	105
Total comprehensive (loss) income	$(4,963)	$22,785	$2,814

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

Approach Resources Inc. ("Approach," "ARI," the "Company," "we," "us" or "our") is an independent energy company engaged in the exploration, development, production and acquisition of unconventional natural gas and oil properties in the United States. We focus on finding and developing natural gas and oil reserves in tight sands and shale gas. We currently operate or have oil and gas properties or interests in Texas, Kentucky and New Mexico.

Consolidation, Basis of Presentation and Significant Estimates

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of the Company and its wholly-owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, the capital expenditure accrual, share-based compensation, and asset retirement obligations. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material.

On November 7, 2007, our board of directors approved a three-for-one stock split in the form of a stock dividend on the issued and outstanding shares of the Company's common stock, which became effective at the completion of our initial public offering ("IPO") on November 14, 2007. Also on November 14, 2007, we acquired all of the outstanding capital stock of Approach Oil & Gas Inc. ("AOG"). The stockholders of AOG received 989,157 shares of Company common stock in exchange for all of AOG's common shares outstanding at that date.

All common shares and per share amounts in the accompanying consolidated financial statements and notes to consolidated financial statements have been adjusted for all periods to give effect to the stock split and the acquisition of AOG. Certain prior year amounts have been reclassified to conform to current year presentation. These classifications have no impact on the net income or loss reported.

Cash and Cash Equivalents

We consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. At times, the amount of cash and cash equivalents on deposit in financial institutions exceeds federally insured limits. We monitor the soundness of the financial institutions and believe the Company's risk is negligible.

Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, notes receivable, accounts payable and accrued liabilities and long-term debt approximate fair value, as of December 31, 2009 and 2008. See Note 7 for commodity derivative fair value disclosures.

Oil and Gas Properties and Operations

Capitalized Costs

Our oil and gas properties comprised the following (in thousands):

	December 31, 2009	December 31, 2008
Mineral interests in properties:		
Unproved properties	$ 10,990	$ 12,687
Proved properties	12,319	11,849
Wells and related equipment and facilities	361,573	332,289
Uncompleted wells, equipment and facilities	2,910	5,980
Total costs	387,792	362,805
Less accumulated depreciation, depletion and amortization	(84,135)	(59,960)
Net capitalized costs	$303,657	$302,845

We follow the successful efforts method of accounting for our oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties and to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have proved reserves. If we determine that the wells do not have proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determination of whether the wells have proved reserves at December 31, 2009 or 2008. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties are charged to expense as incurred. We capitalize interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. Through December 31, 2009, we have capitalized no interest costs because our exploration and development projects generally last less than six months. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion, and amortization with a resulting gain or loss recognized in income.

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves using the unit conversion ratio of six Mcf of gas to one Bbl of oil. Depreciation and depletion expense for oil and gas producing property and related equipment was $24.2 million, $23.3 million and $13 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. We recorded an impairment of $3 and $6.4 million during the years ended December 31, 2009 and 2008, respectively related to our assessment of unproved properties. The 2009 impairment resulted from a write-off of $3 million in acreage costs in Northeast British Columbia, and represents the remaining carrying value we have recorded for the project. The impairment recorded during the year ended December 31, 2008, resulted from write-offs related to drilling costs in our Boomerang project and drilling and completion costs in our Northeast British Columbia project. During the year ended December 31, 2008, we determined that the future cash flows from drilling costs relating to these projects will not exceed the capitalized costs due to market factors. We recorded an impairment during the year ended December 31, 2007, totaling $267,000, and resulting from our conclusion that proved reserves would not be economically recovered from approximately 2,282 acres in Ozona Northeast, leases for which expired in April 2008.

Capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360, formerly Statement of Financial Accounting Standards 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2009, 2008 or 2007.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Ozona Northeast Deep Rights Acquisition

On July 1, 2008, we acquired an additional 95% working interest in all depths below the top of the Strawn formation, compression facilities and rights to approximately 75 miles of gathering lines in our Ozona Northeast field in Crockett and Schleicher Counties, Texas. The properties were acquired from J. Cleo Thompson & James Cleo Thompson, Jr., L.P. and certain other sellers. Before the acquisition, we owned a 100% working interest above the top of the Strawn formation and a 5% working interest below the top of the Strawn formation in Ozona Northeast. As a result of the acquisition, we now own substantially all working interests in all depths of the subsurface in Ozona Northeast.

The purchase price was $12 million subject to post-closing adjustments. We received a post-closing settlement of $1.1 million subsequent to December 31, 2008. Of the purchase price, $500,000 is to be paid pending certain right-of-way matters to be cured. Our preliminary purchase price allocation was $9.5 million to oil and gas properties and $2 million to gathering system, compression facilities and related equipment. Funding was provided through borrowings under our revolving credit facility.

The following is a summary of the purchase price and its allocation (in thousands):

Purchase price:	
Cash paid	$11,500
Asset retirement obligations assumed	995
Post-closing purchase price adjustments	(1,154)
Total	$11,341
Allocation:	
Wells, equipment and related facilities	$11,041
Mineral interests in oil and gas properties	300
Total	$11,341

Oil and Gas Operations

Revenue and Accounts Receivable

We recognize revenue for our production when the quantities are delivered to or collected by the respective purchaser. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. All transportation costs are included in lease operating expense.

Accounts receivable, joint interest owners, consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable, oil and gas sales, consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. No such allowance was considered necessary at December 31, 2009 or 2008.

Oil and Gas Sales Payable

Oil and gas sales payable represents amounts collected from purchasers for oil and gas sales which are either revenues due to other revenue interest owners or severance taxes due to the respective state or local tax authorities. Generally, we are required to remit amounts due under these liabilities within 30 days of the end of the month in which the related production occurred.

Advances from Non-Operators

Advances from non-operators represent amounts collected in advance for joint operating activities. Such amounts are applied to joint interest accounts receivable as related costs are incurred.

Production Costs

Production costs, including compressor rental and repair, pumpers' salaries, saltwater disposal, ad valorem taxes, insurance, repairs and maintenance, expensed workovers and other operating expenses are expensed as incurred and included in lease operating expense on our consolidated statements of operations.

Exploration expenses include dry hole costs, delay rentals and geological and geophysical costs.

Dependence on Major Customers

For the years ended December 31, 2009, 2008 and 2007, we sold substantially all of our oil and gas produced to six purchasers. Additionally, substantially all of our accounts receivable related to oil and gas sales were due from those six purchasers at December 31, 2009 and 2008. We believe that there are potential alternative purchasers and that it may be necessary to establish relationships with new purchasers. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased purchasers. Although we are exposed to a concentration of credit risk, we believe that all of our purchasers are credit worthy.

Dependence on Suppliers

Our industry is cyclical, and from time to time there is a shortage of drilling rigs, equipment, supplies and qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected. We believe that there are potential alternative providers of drilling services and that it may be necessary to establish relationships with new contractors. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased availability of drilling rigs.

Other Property

Furniture, fixtures and equipment are carried at cost. Depreciation of furniture, fixtures and equipment is provided using the straight-line method over estimated useful lives ranging from three to ten years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition.

Depreciation expense for other property and equipment was $296,000, $180,000 and $88,000 for the years ended December 31, 2009, 2008 and 2007, respectively.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the year of the enacted tax rate change.

Derivative Activity

All derivative instruments are recorded on the balance sheet at fair value. Changes in the instruments' fair values are recognized in the statement of operations immediately unless specific commodity derivative accounting criteria are met. For qualifying cash flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive (loss) income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in cumulative other comprehensive (loss) income are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized (loss) gain on commodity derivatives."

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our natural gas and oil production. Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. Realized gains as losses are also included in other income (expense) on our consolidated statements of operations.

Accrued Liabilities

Following is a summary of our accrued liabilities at December 31, 2009 and 2008:

	2009	2008
Capital expenditures accrued	$ 9,362	$8,173
Operating expenses and other	1,517	1,587
Income taxes payable	56	50
Total	$10,935	$9,810

Asset Retirement Obligations

Our asset retirement obligations relate to future plugging and abandonment expenses on oil and gas properties. Based on the expected timing of payments, the full asset retirement obligation is classified as non-current. There were no significant changes to the asset retirement obligations for the years ended December 31, 2009, 2008 and 2007.

Foreign Currency Translation

The functional currency of the countries in which we operate is the U.S. dollar in the United States and the Canadian Dollar in Canada. Assets and liabilities of our Canadian subsidiary that are denominated in currencies other than the Canadian Dollar are translated at current exchange rates. Gains and losses resulting from such translations, along with gains or losses realized from transactions denominated in currencies other than the Canadian Dollar are included in operating results on our statements of operations. For purposes of consolidation, we translate the assets and liabilities of our Canadian Subsidiary into U.S. Dollars at current exchange rates while revenues and expenses are translated at the average rates in effect for the period. The related translation gains and losses are included in accumulated other comprehensive loss within stockholders' equity on our consolidated balance sheets. During the years ended December 31, 2009 and 2007, we recognized translation gains, net of related income tax, of $266,000 and $105,000, respectively. During the year ended December 31, 2008, we recognized a $601,000 translation loss, net of the related income tax, respectively.

Share-Based Compensation

We measure and record compensation expense for all share-based payment awards to employees and outside directors based on estimated grant date fair values. We recognize compensation costs for awards granted over the requisite service period based on the grant date fair value.

Earnings Per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is anti-dilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share, (dollars in thousands, except per-share amounts):

	Year Ended December 31, 2009		
	Loss (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net loss	$(5,229)	20,869,832	$(0.25)
Effect of dilutive securities(1):			
Share-based compensation, treasury method	—	—	
Net loss plus assumed conversions	$(5,229)	20,869,832	$(0.25)

	Year Ended December 31, 2008		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net income	$23,386	20,647,339	$1.13
Effect of dilutive securities:			
Share-based compensation, treasury method	—	177,566	
Net income plus assumed conversions	$23,386	20,824,905	$1.12

	Year Ended December 31, 2007		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net income	$2,709	11,036,799	$0.25
Effect of dilutive securities:			
Share-based compensation, treasury method	—	146,908	
Convertible notes(2)	—	—	
Net income plus assumed conversions	$2,709	11,183,707	$0.24

(1) Approximately 410,000 options to purchase our common stock were excluded from this calculation because they were anti-dilutive.

(2) The outstanding principal and interest under our convertible debt was converted on November 7, 2007 into shares of common stock (see Note 2 for further discussion). Approximately 1.8 million shares were excluded from assumed conversions because they were anti-dilutive for the year ended December 31, 2007.

Current Accounting Pronouncements

Effective January 1, 2009, we adopted ASC 260-10 (formerly Staff Position No. EITF 03-6-1), "Determining whether Instruments Granted in Share-Based Payment Transactions are Participating Securities," which provides that unvested share-based payment awards that contain non-forfeitable rights to dividend or dividend equivalents (whether paid or unpaid) are participating securities, and, therefore need to be included in the earnings allocation in computing earnings per share under the two-class method. We adopted the provisions of this standard on January 1, 2009, with no significant impact on our reported earnings per share.

Effective January 1, 2009, we adopted ASC 815-10 (formerly Statement of Financial Accounting Standards ("SFAS") 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement 133*), which amends and expands the disclosure requirements with the intent to provide users of financial statements with an enhanced understanding of (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and the related hedged items are accounted for; and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. See Note 7 to our consolidated financial statements for additional disclosures.

In May 2009, the Financial Accounting Standards Board (the "FASB") issued ASC 855-10 (formerly SFAS No. 165) *Subsequent Events*, which establishes general standards of accounting for and disclosure of events that occur subsequent to the date of our consolidated financial statements. We adopted this standard upon issuance with no impact on our financial position or results of operations.

In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168), *Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles*. The FASB Accounting Standards Codification™ (the "Codification") has become the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in accordance with Generally Accepted Accounting Principles ("GAAP"). All existing accounting standard documents are superseded by the Codification and any accounting literature not included in the Codification will not be authoritative. Rules and interpretive releases of the SEC issued under the authority of federal securities laws, however, will continue to be the source of authoritative generally accepted accounting principles for SEC registrants. Effective September 30, 2009, all references made to GAAP in our consolidated financial statements will include the new Codification numbering system along with original references. The

Codification does not change or alter existing GAAP and, therefore, will not have an impact on our financial position, results of operations or cash flows.

On December 31, 2008, the Securities and Exchange Commission (the "SEC") released a Final Rule, *Modernization of Oil and Gas Reporting*, approving revisions designed to modernize oil and gas reserve reporting requirements. The new reserve rules are effective for our financial statements for the year ended December 31, 2009 and our 2009 year-end proved reserve estimates. See Note 12 to our consolidated financial statements for additional disclosures. The most significant revisions to the reporting requirements include:

- *Commodity prices.* Economic producibility of reserves is now based on the unweighted, arithmetic average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, unless prices are defined by contractual arrangements;
- *Undeveloped oil and gas reserves.* Reserves may be classified as "proved undeveloped" for undrilled areas beyond one offsetting drilling unit from a producing well if there is reasonable certainty that the quantities will be recovered;
- *Reliable technology.* The rules now permit the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;
- *Unproved reserves.* Probable and possible reserves may be disclosed separately on a voluntary basis;
- *Preparation of reserves estimates.* Disclosure is required regarding the internal controls used to assure objectivity in the reserves estimation process and the qualifications of the technical person primarily responsible for preparing reserves estimates; and
- *Third party reports.* We are now required to file the report of any third party used to prepare or audit reserves our estimates.

In addition, in January 2010, FASB issued Account Standards Update (the "Update") 2010-03, "Oil and Gas Reserve Estimation and Disclosures," to provide consistency with the new reserve rules. The Update amends existing standards to align the reserves calculation and disclosure requirements under GAAP with the requirements in the SEC's reserve rules. We adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate.

The new reserve rules resulted in the use of lower prices for natural gas, oil and NGLs than would have resulted under the previous reporting requirements. Under the new reserve rules, our estimated proved reserves increased by 7,860 MMcfe. Under the previous reserve rules, our estimated total proved reserves of natural gas, oil and NGLs would have increased by 20,122 MMcfe. Therefore, the effect of the new reserve rules was a negative revision of 12,262 MMcfe.

Because we use quarter-end reserves and add back current production to calculate quarterly depletion, depreciation and amortization expense, or DD&A, adoption of these new standards had an impact on DD&A for the fourth quarter of 2009. We estimate the impact of using the unweighted, arithmetic average on the closing price on the first day of each month for the 12-month period prior to December 31, 2009, as required by the new reserve rules, instead of year-end commodity prices, to be an increase in DD&A for the fourth quarter of 2009 of approximately $400,000 ($0.01 per share), net of related income taxes.

In January 2010, the Financial Accounting Standards Board issued amendments to Fair Value Measurements and Disclosures under ASC Topic 820. Effective for our 2010 financial statements, this guidance provides for disclosures of significant transfers in an out of Levels 1 and 2. In addition, the guidance clarifies existing disclosure requirements regarding inputs and valuation techniques as well as the appropriate level of disaggregation for fair value measurements and disclosures. Effective for our 2011 financial statements, this guidance provides for disclosures of activity on a gross basis within Level 3 reconciliation.

2. Contribution Agreement and Initial Public Offering

Contribution Agreement

On November 14, 2007, the Company acquired all of the outstanding capital stock of AOG and acquired the 30% working interest in the Ozona Northeast field (the "Neo Canyon interest") that the Company did not already own from Neo Canyon Exploration, L.P. ("Neo Canyon"). Upon the closing of the contribution agreement, Neo Canyon and each of the stockholders of AOG received shares of Company common stock in exchange for their respective contributions. Neo Canyon received an aggregate of 4,239,243 shares of Company common stock, of which 2,061,290 shares were offered in the Company's IPO, 156,805 shares were subject to the over-allotment option granted to the underwriters and 2,021,148 shares were redeemed by the Company for cash. The stockholders of AOG received an aggregate of 989,157 shares of Company common stock. Our acquisition of AOG represents a reorganization of companies under common control. Accordingly, all of our consolidated financial statements have been presented to reflect the financial position, results of operations and cash flows as if we had owned AOG since its inception.

The acquisition cost of the Neo Canyon interest was $60.7 million, representing 4,239,243 shares of Company common stock at $12.00 per share, our IPO price, and the assumption of related deferred income tax liabilities and asset retirement obligations at that date along with post-closing purchase price adjustments resulting from operating results of the properties acquired between the effective date and the closing date of the acquisition. The existing tax basis assumed from the acquisition was finalized during the year ended December 31, 2008. The adjustment made during the year ended December 31, 2008 resulted in a $376,000 increase in deferred tax liabilities, $133,000 in additional post-closing purchase price adjustments and an increase in oil and gas properties of $509,000. The following is a summary of the final purchase price and its allocation (in thousands):

Purchase price:	
Issuance of 4,239,243 shares of Approach Resources Inc. common stock valued at $12.00 per share	$50,871
Deferred tax liabilities assumed	9,465
Asset retirement obligations assumed	133
Post-closing purchase price adjustments	265
Total	$60,734
Allocation:	
Wells, equipment and related facilities	$59,936
Mineral interests in oil and gas properties	798
Total	$60,734

Our results of operations include the operating results of the interest acquired from Neo Canyon beginning November 14, 2007. The following condensed pro forma information gives effect to the acquisition as if it had occurred on January 1, 2006. The pro forma information has been included in the notes as required by GAAP and is provided for comparison purposes only. The pro forma financial information is not necessarily indicative of the financial results that would have occurred had the acquisition been effective on the dates indicated and should not be viewed as indicative of operations in the future.

	Years Ended December 31,	
	2007	2006
Operating revenues	$52,285	$66,230
Total operating expenses	$38,651	$33,772
Earnings applicable to common stock	$ 7,224	$27,864
Net earnings per share — basic	$ 0.49	$ 2.05
Net earnings per share — diluted	$ 0.49	$ 2.01

Initial Public Offering

On November 14, 2007, we completed the IPO of our common stock. In connection with our IPO and exercise by the underwriters of their overallotment option, we sold 6,598,572 shares of our common stock in November 2007 at $12.00 per share. The gross proceeds of our IPO and over-allotment option were approximately $79.2 million, which resulted in net proceeds to the Company of $73.6 million after deducting underwriter discounts and commissions of approximately $5.6 million. The aggregate net proceeds of approximately $73.6 million received by the Company were used as follows (in millions):

Repayment of revolving credit facility	$51.1
Repurchase of stock held by selling stockholder	$22.5

Stock Split

A three-for-one stock split in the form of a stock dividend on the issued and outstanding shares of Company common stock was declared on November 7, 2007, and was paid on November 14, 2007 in authorized but unissued shares of Company common stock to holders of record of shares of common stock at the close of business on November 13, 2007, so that each share of common stock outstanding on that date entitled its holder to receive two additional shares of common stock.

Convertible Notes

Upon the consummation of the IPO, the convertible notes discussed in Note 8 and related accrued interest were automatically converted into shares of our common stock. The number of shares of common stock issued upon the automatic conversion of these notes was 920,631 to Yorktown Energy Partners VII, L.P. and 920,631 to Lubar Equity Fund, LLC. The shares of common stock that were issued to Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC upon such automatic conversion are entitled to the same registration rights as those provided to certain holders of common stock in connection with the contribution agreement.

Additionally, we recorded $1.5 million of interest expense related to a beneficial conversion feature attributable to the convertible notes at the time of conversion.

3. Loans to Stockholders and Stockholder Notes Payable

During each of the years ended December 31, 2003 and 2004, we issued 450,000 shares of common stock in exchange for $585,000 in cash and $3.9 million in full-recourse notes receivable from employees and entities owned by or affiliated with management.

During February 2006, one of our employees voluntarily resigned. At the time of his resignation, the employee held 103,845 shares of ARI common stock and options to acquire 28,845 shares of ARI common stock at $3.33 per share. Additionally, the employee owed us $334,000 of principal and interest under a full-recourse note receivable for the initial purchase of his shares. On February 17, 2006, we entered into an agreement to repurchase the shares and options, net of the principal and interest due under the note receivable. We paid $12.82 per share, the fair value of our common stock on February 17, 2006, for the 103,845 shares, or $1.3 million less the outstanding principal and interest of $334,000 for total cash of $1 million. As discussed in Note 6, we paid $273,000 in cash to cancel the vested options held by the employee on February 17, 2006.

On January 8, 2007, the remaining notes and accrued interest were repaid in exchange for 253,650 shares of common stock held by management, based on the fair value of ARI common shares of $16.50 per share at that date. The notes provided for interest at six percent per annum and were payable upon the earlier of December 31, 2008, the registration of the underlying common stock, or upon a merger with another entity or upon a divestiture of our assets. The notes were collateralized by the underlying common stock purchased and are reported in the accompanying balance sheet as loans to stockholders including accrued interest, reducing stockholders' equity. Interest earned is reported net of related income tax as a component of additional paid-in capital in the accompanying statement of changes in stockholders' equity.

The following is a summary of the balance of principal and interest outstanding under the notes receivable at December 31, 2006 (in thousands):

	2006
Principal	$3,614
Accrued interest	570
Total	$4,184

4. Revolving Credit Facility

We have a $200 million revolving credit facility with a borrowing base set at $115 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

Currently, the maturity date under our revolving credit facility is July 31, 2011. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of non-used borrowings available under our revolving credit facility.

Effective April 8, 2009, we entered into a fourth amendment (the "Fourth Amendment") to our credit agreement. The Fourth Amendment reaffirmed the borrowing base of $100 million under the credit agreement as well as the commitment percentages of the agent bank and participating banks. The Fourth Amendment also revised the applicable rate schedule to (i) increase the Eurodollar rate margin from a range of 1.25% to 2.00% to a range of 2.25% to 3.25%, determined by the then-current percentage of the borrowing base that is drawn, (ii) increase the base rate margin from a flat rate of 0.00% to a range of 1.25% to 2.25%, determined by the then-current percentage of the borrowing base that is drawn, and (iii) increase the unused commitment fee rate from 0.375% to 0.50%.

Effective July 8, 2009, we entered into a fifth amendment to our credit agreement, which extended the maturity date under our revolving credit facility by one year to July 31, 2011. In consideration for extending the maturity date, we paid a $250,000 extension fee, calculated as 0.25% of the current commitment amount of $100 million. The $250,000 fee is being amortized into interest expense through the extended maturity date.

Effective October 30, 2009, we entered into a sixth amendment to our credit agreement, which increased the borrowing base under the credit agreement to $115 million from $100 million.

Effective February 1, 2010, we entered into a seventh amendment to our credit agreement, which replaced The Frost National Bank as the administrative agent under the Credit Agreement with JPMorgan Chase Bank, N.A., as successor agent.

We had outstanding borrowings of $32.3 million and $43.5 million under our revolving credit facility at December 31, 2009 and 2008, respectively. The weighted average interest rate applicable to our outstanding borrowings was 3.20% and 3.25% at December 31, 2009 and 2008, respectively. We also had outstanding unused letters of credit under our revolving credit facility totaling $400,000 at December 31, 2009, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

At February 28, 2010, we had $37.9 million outstanding under our revolving credit facility, with a weighted average interest rate of 3.42%.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.

- a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 3.5 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other non-cash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or non-recurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as more specifically defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At December 31, 2009, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

5. Share-Based Compensation

In June 2007, the board of directors and stockholders approved the 2007 Stock Incentive Plan ("the 2007 Plan"). Under the 2007 Plan, we may grant restricted stock, stock options, stock appreciation rights, restricted stock units, performance awards, unrestricted stock awards and other incentive awards. The 2007 Plan reserves 10 percent of our outstanding common shares as adjusted on January 1 of each year, plus shares of common stock that were available for grant of awards under our prior plan. Awards of any stock options are to be priced at not less than the fair market value at the date of the grant. The vesting period of any stock award is to be determined by the board or an authorized committee at the time of the grant. The term of each stock option is to be fixed at the time of grant and may not exceed 10 years. Shares issued upon stock options exercised are issued as new shares.

Share-based compensation expense amounted to $1.8 million, $1.1 million and $4.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. Such amounts represent the estimated fair value of stock awards for which the requisite service period elapsed during the years.

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the years ended December 31, 2008 and 2007. There were no stock option grants during the year ended December 31, 2009.

	2008	2007
Expected dividends	—	—
Expected volatility	64%	68%
Risk-free interest rate	2.7%	3.9%
Expected life	6 years	6 years

We have not paid out dividends historically, thus the dividend yields are estimated at zero percent.

Since our shares were not publicly traded prior to the IPO on November 8, 2007, we used an average of historical volatility rates based upon other companies within our industry for awards in 2008 and 2007. Management believes that these average historical volatility rates are currently the best available indicator of expected volatility.

The risk-free interest rate is the implied yield available for zero-coupon U.S. government issues with a remaining term of five years.

The expected lives of our options are determined based on the term of the option using the simplified method outlined in Staff Accounting Bulletin 110.

Assumptions are reviewed each time there is a new grant and may be impacted by actual fluctuation in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for the options granted or modified and impacts the amount of compensation expense recognized on the consolidated statement of operations.

The following table summarizes stock options outstanding and activity as of and for the years ended December 31, 2009, 2008 and 2007, (dollars in thousands):

	Shares Subject to Stock Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at January 1, 2007	346,155	$ 3.33		
Granted	205,950	$12.05		
Exercised	(72,114)	$ 3.33		
Outstanding at December 31, 2007	479,991	$ 7.07	8.02	$2,779
Granted	74,345	$14.90		
Exercised	(63,459)	$ 3.33		
Canceled	(56,575)	$12.40		
Outstanding at December 31, 2008	434,302	$ 8.47	7.34	$ 837
Granted	—	$ —		
Exercised	—	$ —		
Canceled	(24,975)	$12.00		
Outstanding at December 31, 2009	409,327	$ 8.03	6.10	$ —
Exercisable (fully vested) at December 31, 2009	320,480	$ 6.52	5.56	$ 385

The fair market value of the stock options granted during the years ended December 31, 2008 and 2007 was $8.96 per share and $7.69 per share, respectively. Total unrecognized share-based compensation expense from unvested stock options as of December 31, 2009 was $529,000, and will be recognized over a remaining service period of 1.25 years. The intrinsic value of the options exercised during the years ended December 31, 2008 and 2007 was $770,000 and $634,000, respectively. There was no tax benefit recognized in relation to the stock options exercised.

Share grants totaling 204,790, 35,948 and 411,041 shares with an approximate aggregate market value of $1.7 million, $733,000 and $5.2 million at the time of grant were granted to employees during the years ended December 31, 2009, 2008 and 2007, respectively. The tax benefit recognized in relation to the vested shares was $86,000. A summary of the status of non-vested shares for the years ended December 31, 2009, 2008 and 2007, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2007	—	$ —
Granted	411,041	12.70
Vested	(368,541)	12.26
Nonvested at December 31, 2007	42,500	16.50
Granted	35,948	20.39
Vested	(21,250)	16.50
Canceled	(1,175)	15.48
Nonvested at December 31, 2008	56,023	$18.96
Granted	204,790	$ 8.40
Vested	(32,182)	18.07
Canceled	(2,751)	12.39
Nonvested at December 31, 2009	225,880	$ 9.73

The unrecognized compensation of $896,000 related to the nonvested shares will be recognized over a remaining service period of 2.83 years.

6. Income Taxes

Our (benefit) provision for income taxes comprised the following during the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Current:			
Federal	$ —	$ (214)	$ 188
State	—	177	—
Total current	$ —	$ (37)	$ 188
Deferred:			
Federal	$(1,056)	$11,919	$(296)
State	271	229	—
Total deferred	$ (785)	$12,148	$(296)
(Benefit) provision for income taxes	$ (785)	$12,111	$(108)

Total income tax (benefit) expense differed from the amounts computed by applying the U.S. Federal statutory tax rates to pre-tax income for the years ended December 31, 2009, 2008 and 2007, as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Statutory tax at 34%	$(2,045)	$12,069	$ 884
State taxes, net of federal impact	72	199	29
Permanent differences(1)	231	235	609
Other differences(2)	957	(392)	(35)
Change in valuation allowance	—	—	(1,595)
Total	$ (785)	$12,111	$ (108)

(1) Amount primarily relates to share-based compensation expense for the years ended December 31, 2009 and 2008, and the beneficial conversion feature on the convertible notes for the year ended December 31, 2007.

(2) Approximately $600,000 relates to a change in our estimated income tax for the year ended December 31, 2008.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a long-term liability of $38.4 million and $35.9 million at December 31, 2009 and 2008, respectively. At December 31, 2009, $255,000 of deferred taxes expected to be realized during 2010 was included in current assets within prepaid expenses and other current assets. Significant components of net deferred tax assets and liabilities are (in thousands):

	Years Ended December 31,	
	2009	2008
Deferred tax assets:		
Net operating loss carryforwards	$ 7,214	$ 2,363
Unrealized loss on commodity derivatives	301	—
Other	362	694
Total deferred tax assets	$ 7,877	$ 3,057
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods — oil and gas properties	(45,996)	(38,948)
Unrealized gain on commodity derivatives	—	(2,770)
Total deferred tax liabilities	(45,996)	(41,718)
Net deferred tax (liability)	$(38,119)	$(38,661)

Net operating loss carryforwards for tax purposes have the following expiration dates (in thousands):

Expiration Dates	Amounts
2024	$ 1,523
2025	1,082
2026	2,594
2027	2,703
2028	1,308
2029	12,009
Total	$21,219

7. Derivatives

At December 31, 2009, we had the following commodity derivatives positions outstanding:

Period	Volume (MMBtu) Monthly	Volume (MMBtu) Total	$/MMBtu Fixed
NYMEX — Henry Hub			
Price swaps 2010	150,000	1,800,000	$ 5.85
Price swaps 2010	150,000	1,800,000	$ 6.40
Price swaps 2010	100,000	1,200,000	$ 6.36
WAHA basis differential			
Basis swaps 2010	415,000	4,980,000	$(0.71)
Basis swaps 2011	300,000	3,600,000	$(0.53)

The following summarizes the fair value of our open commodity derivatives as of December 31, 2009 and December 31, 2008 (in thousands):

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	December 31, 2009	December 31, 2008	Balance Sheet Location	December 31, 2009	December 31, 2008
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives	$786	$8,017	Unrealized loss on commodity derivatives	$2,668	$—

The following summarizes the change in the fair value of our commodity derivatives (in thousands):

	Income Statement Location	Fair Value Year Ended December 31, 2009	2008	2007
Derivatives not designated as hedging instruments				
Commodity derivatives	Unrealized (loss) gain on commodity derivatives	$(9,899)	$ 7,149	$(3,637)
	Realized gain on commodity derivatives	14,659	2,936	4,732
		$ 4,760	$10,085	$ 1,095

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the collar contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that 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 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2009, we had no Level 1 measurements.

- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2009, all of our commodity derivatives were valued using Level 2 measurements.

- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2009, our Level 3 measurements were limited to our asset retirement obligation.

8. Convertible Notes

On June 25, 2007, Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC loaned an aggregate of $20 million to AOG under two convertible promissory notes of $10 million each. These notes bore interest at a rate of 7.00% per annum and had a maturity date of June 25, 2010, at which time all principal and interest would have been due. These notes were initially convertible at the election of the lender into shares of equity securities of AOG at $100 per share on December 31, 2007, or earlier if we sold substantially all of the assets of AOG. Upon consummation of our IPO, the notes automatically, and without further action required by any person, converted into shares of ARI common stock. The number of shares of ARI common stock issued upon the automatic conversion of these notes was equal to the quotient obtained by dividing (a) the outstanding principal and accrued interest on each respective note by (b) the IPO price per share, less any underwriting discount per share for the shares of ARI common stock that were issued in our IPO. The shares of our common stock issued to Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC upon such automatic conversion are entitled to the same registration rights as those provided to certain holders of our common stock in connection with the contribution agreement. The total principal and interest owed under these notes at the time of the IPO was $20.5 million. Yorktown Energy Partners VII, L.P. is an affiliate of Yorktown Partners LLC, which has one representative, Bryan H. Lawrence, who serves as a member of our board of directors. Lubar Equity Fund, LLC is an affiliate of Sheldon B. Lubar, who serves as a member of our board of directors.

The automatic conversion of the notes into shares of ARI common stock upon the closing of our IPO constituted a contingent beneficial conversion feature because the price per share into which these notes were convertible was less than the price paid by other parties acquiring ARI common stock. Immediately upon the closing of our IPO, we were required to measure the intrinsic value of the beneficial conversion feature and record such value as a charge to interest expense. The value of the beneficial conversion feature, and therefore the amount of interest expense, that was recognized when the notes were converted on the date of the IPO, was $1.5 million.

9. Canadian Unconventional Gas Investment

In May 2007, we acquired shares of common stock of a Canadian-based private exploration company focused on tight gas and shale gas opportunities in Canada. Our investment amounted to approximately $917,000 and is a non-controlling interest accounted for using the cost method. We have written off the carrying value of our minority equity investment in the Canadian operator by recognizing a non-cash charge to earnings because we believe we will not recover our investment.

10. Commitments and Contingencies

We have employment agreements with two of our officers. These agreements are automatically renewed for successive terms of one year unless employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, is approximately $700,000 at December 31, 2009.

We lease our office space in Fort Worth, Texas, under a non-cancelable agreement that expires on December 31, 2012. In addition, we had a lease on our former office space that expired in May 2009. We had sublease agreements for the former office space that provided for a recovery of a substantial portion of those rentals.

We also have non-cancelable operating lease commitments related to office equipment that expire by 2012. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements, net of minimum rentals to be received under non-cancelable subleases as of December 31, 2009 (in thousands):

2010	$ 410
2011	419
2012	353
Total	$1,182

Rent expense under our lease arrangements amounted to $461,000, $299,000 and $198,000 for the years ended December 31, 2009, 2008 and 2007, respectively.

Litigation

Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A, District Court of Limestone County, Texas. On July 2, 2009 our operating subsidiary filed a lawsuit against EnCana EnCana Oil & Gas (USA) Inc., or EnCana, for breach of the JOA covering our North Bald Prairie project in East Texas and seeking damages for nonpayment of amounts owed under the joint operating agreement, or JOA, as well as declaratory relief. We contend that such amounts owed by EnCana are at least $2.1 million, plus attorneys' fees, costs and other amounts to which we might be entitled under law or in equity. The amount owed to us is included in other non-current assets on our balance sheet at December 31, 2009. As we previously have disclosed, in December 2008, EnCana notified us that it was exercising its right to become operator of record for joint interest wells in North Bald Prairie under an operator election agreement between the parties. EnCana contends that it does not owe us for part or all of joint interest billings incurred after EnCana provided us with notice of EnCana's election to assume operatorship in December 2008. EnCana also contends that certain of the disputed operations were unnecessary, while other charges are improper because we failed to obtain EnCana's consent under the JOA prior to undertaking the operations. We have informed the Court that we will transfer operatorship to EnCana when EnCana has made all payments it owes under the JOA.

We also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

Environmental Issues

We are engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental clean up of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operation thereof. In connection with our acquisition of existing or previously drilled well bores, we may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, we would be responsible for curing such a violation. No claim has been made, nor are we aware of any liability that exists, as it relates to any environmental clean up, restoration or the violation of any rules or regulations relating thereto.

11. Oil and Gas Producing Activities

Set forth below is certain information regarding the costs incurred for oil and gas property acquisition, development and exploration activities (in thousands):

	For the Years Ended December 31,		
	2009	2008	2007
Property acquisition costs:			
Unproved properties	$ 1,081	$ 2,695	$ 5,480
Proved properties	57	12,189	59,594
Exploration costs	1,483	5,007	9,897
Development costs(1)	28,121	84,193	37,451
Total costs incurred	$30,742	$104,084	$112,422

(1) For the years ended December 31, 2009 and 2008, development costs include $170,000 and $3.5 million in non-cash asset retirement obligations, respectively.

Set forth below is certain information regarding the results of operations for oil and gas producing activities (in thousands):

	For the Years Ended December 31,		
	2009	2008	2007
Revenues	$ 40,648	$ 79,869	$ 39,114
Production costs	(9,773)	(11,823)	(5,474)
Exploration expense	(1,621)	(1,478)	(883)
Impairment	(2,964)	(6,379)	(267)
Depletion	(24,660)	(23,338)	(13,010)
Income tax expense	(554)	(12,529)	(6,623)
Results of operations	$ 1,076	$ 24,322	$ 12,857

12. Disclosures About Oil and Gas Producing Activities (unaudited)

Proved Reserves

The estimates of proved reserves and related valuations for the years ended December 31, 2009, 2008 and 2007 were prepared by DeGolyer and MacNaughton, independent petroleum engineers. Each year's estimate of proved reserves and related valuations were also prepared in accordance with then-current provisions of ASC 932 and Statement of Financial Accounting Standards 69, or SFAS 69, Disclosures about Oil and Gas Producing Activities.

Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. All of our estimated oil and natural gas reserves are attributable to properties within the United States. A summary of Approach's changes in quantities of proved oil and natural gas reserves for the years ended December 31, 2007, 2008 and 2009, are as follows:

Proved Developed and Proved Undeveloped Reserves	Natural Gas (MMcf)	Oil & NGLs (MBbls)	Total (MMcfe)
Balance—December 31, 2006	98,657	1,122	105,389
Extensions and discoveries	36,194	1,807	47,036
Purchases of minerals in place	40,174	378	42,442
Production	(4,801)	(84)	(5,305)
Revisions to previous estimates	(9,073)	(15)	(9,162)
Balance—December 31, 2007	161,151	3,208	180,400
Extensions and discoveries	22,879	3,228	42,249
Purchases of minerals in place	7,312	67	7,711
Production	(7,092)	(277)	(8,755)
Revisions to previous estimates	(11,383)	141	(10,537)
Balance—December 31, 2008	172,867	6,367	211,068
Extensions and discoveries	14,301	2,682	30,395
Purchases of minerals in place	—	—	—
Production	(6,320)	(415)	(8,808)
Revisions to previous estimates	(12,514)	(202)	(13,727)
Balance—December 31, 2009	168,334	8,432	218,928
Proved Developed Reserves:			
December 31, 2007	70,251	1,268	77,859
December 31, 2008	84,217	3,014	102,301
December 31, 2009	74,804	3,118	93,512

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2009, 2008 and 2007:

Year Ended December 31, 2009

Our drilling programs in Cinco Terry and Ozona Northeast resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. For the year ended December 31, 2009, of the 13,727 MMcfe downward revision of our previous estimate, 10,152 MMcfe and 3,574 MMcfe relate to price and performance revisions, respectively. The gas price used to estimate our proved reserves decreased from $6.04 per Mcf at December 31, 2008, to $3.88 per Mcf at December 31, 2009. The performance revision primarily related to producing properties in our North Bald Prairie field in East Texas. Well performance data collected during 2009 for North Bald Prairie indicate that these assets underperformed our year-end 2008 decline estimates. Accordingly, we removed 4,514 MMcfe from proved reserves recorded for North Bald Prairie. We also removed 620 MMcfe in Ozona Northeast due to performance revisions. Partially offsetting the removal of 5,134 MMcfe from proved reserves recorded for North Bald Prairie and Ozona Northeast was a positive performance revision of 1,560 MMcfe in our Cinco Terry field in West Texas.

Year Ended December 31, 2008

Our drilling programs in Ozona Northeast, Cinco Terry and North Bald Prairie resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. Additionally, during 2008 we acquired 7,711 MMcfe of proved reserves in Ozona Northeast, which accounts for the additional proved reserve quantities listed as purchases of minerals in place. Downward revisions to proved reserves of 7,405 MMcfe are the result of a significant decline in commodity prices during the third and fourth quarters of 2008. The gas price used to estimate our proved reserves decreased from $8.10 per Mcf at December 31, 2007 to $6.04 per Mcf at December 31, 2008. Downward revisions to proved reserves of 3,132 MMcfe, which represents 1.7% of the our estimated proved reserves of 180,399 MMcfe at December 31, 2007, was based on the accumulation of additional production results that occurred during 2008 in Ozona Northeast and North Bald Prairie. Wells that were primarily responsible for downward revisions had little production history (as proved developed producing wells) or no production history (as proved undeveloped locations) when reserves for those wells and locations were booked at December 31, 2007. At December 31, 2008, after recording and reviewing a year's worth of production history, we determined to revise the estimated ultimate recoveries for these wells downward.

Year Ended December 31, 2007

Our drilling programs in Ozona Northeast, Cinco Terry and North Bald Prairie resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. Additionally, we completed the acquisition of the Neo Canyon interest in Ozona Northeast accounting for the additional quantities listed as purchases of minerals in place. The downward revisions to proved reserves are the result of performance in Ozona Northeast. Partially offsetting the downward revisions was an increase in the average gas price attributable to our proved reserves from $6.55 per Mcf at December 31, 2006 to $8.10 per Mcf at December 31, 2007.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with then-current provisions of ASC 932 and SFAS 69. Future cash inflows were computed by applying the unweighted, arithmetic average on the closing price on the first day of each month for the 12-month period prior to December 31, 2009, to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved.

Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of Approach's oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Future cash flows	$1,007,703	$1,248,661	$1,567,251
Future production costs	(358,276)	(411,177)	(401,579)
Future development costs	(213,161)	(201,259)	(191,738)
Future income tax expense	(88,796)	(157,503)	(285,384)
Future net cash flows	347,470	478,722	688,550
10% annual discount for estimated timing of cash flows	(267,479)	(336,087)	(472,590)
Standardized measure of discounted future net cash flows	$ 79,991	$ 142,635	$ 215,960

Future cash flows as shown above were reported without consideration for the effects of commodity derivative transactions outstanding at each period end.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Balance, beginning of period	$142,635	$ 215,960	$ 77,877
Net change in sales and transfer prices and in production (lifting) costs related to future production	(89,649)	(148,739)	57,231
Changes in estimated future development costs	(29,647)	(72,754)	(39,506)
Sales and transfers of oil and gas produced during the period	(30,877)	(68,037)	(33,640)
Net change due to extensions, discoveries and improved recovery	26,648	58,249	107,864
Net change due to purchase of minerals in place	—	10,632	97,328
Net change due to revisions in quantity estimates	(12,034)	(14,526)	(21,001)
Previously estimated development costs incurred during the period	28,121	89,942	28,026
Accretion of discount	18,743	29,369	12,843
Other	(3,449)	(8,712)	8,077
Net change in income taxes	29,500	51,251	(79,139)
Standardized measure of discounted future net cash flows	$ 79,991	$ 142,635	$215,960

The commodity prices in effect at December 31, 2009, 2008 and 2007 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows:

	2009	2008	2007
Oil (per Bbl)	$56.04	$39.60	$93.30
Natural gas liquids (per Bbl)	$27.20	$23.00	$60.09
Gas (per Mcf)	$ 3.88	$ 6.04	$ 8.10

13. Supplementary Data

Selected Quarterly Financial Data (unaudited), (dollars in thousands, except per-share amounts):

	2009 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 11,881	$ 8,787	$ 9,915	$ 10,065
Net operating expenses	(15,650)	(10,715)	(10,713)	(12,557)
Interest expense, net	(434)	(451)	(457)	(445)
Realized gain on commodity derivates	2,763	4,271	4,444	3,181
Unrealized (loss) gain on commodity derivatives	(1,310)	(6,414)	(4,320)	2,145
(Loss) income before income taxes	(2,750)	(4,522)	(1,131)	2,389
Income tax (benefit) provision	(468)	(1,378)	(460)	1,521
Net (loss) income	$ (2,282)	$ (3,144)	$ (671)	$ 868
Basic net (loss) income applicable to common stockholders per common share	$ (0.11)	$ (0.15)	$ (0.03)	$ 0.04
Diluted net (loss) income applicable to common stockholders per common share	$ (0.11)	$ (0.15)	$ (0.03)	$ 0.04

	2008 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 14,692	$22,015	$ 24,144	$19,018
Impairment of non-producing properties	(6,379)	—	—	—
Net operating expenses	(14,485)	(9,749)	(11,855)	(9,803)
Interest expense, net	(355)	(423)	(343)	(148)
Impairment of investment	(917)	—	—	—
Realized gain (loss) on commodity derivates	3,612	(195)	(542)	61
Unrealized gain (loss) on commodity derivatives	3,089	18,611	(9,672)	(4,879)
(Loss) income before income taxes	(743)	30,259	1,732	4,249
Income tax (benefit) provision	(591)	10,411	804	1,487
Net (loss) income	$ (152)	$19,848	$ 928	$ 2,762
Basic net (loss) income applicable to common stockholders per common share	$ (0.01)	$ 0.96	$ 0.04	$ 0.13
Diluted net (loss) income applicable to common stockholders per common share	$ (0.01)	$ 0.95	$ 0.04	$ 0.13

	2007 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 11,740	$ 8,292	$ 9,690	$ 9,392
Net operating expenses	(14,503)	(5,644)	(5,661)	(6,581)
Interest expense, net	(2,157)	(1,108)	(998)	(956)
Realized gain on commodity derivates	1,409	1,080	88	2,155
Unrealized (loss) gain on commodity derivatives	(1,520)	785	1,724	(4,626)
(Loss) income before income taxes	(5,031)	3,405	4,843	(616)
Income tax (benefit) provision	(3,238)	1,312	1,853	(35)
Net (loss) income	$ (1,793)	$ 2,093	$ 2,990	$ (581)
Basic net (loss) income applicable to common stockholders per common share	$ (0.12)	$ 0.22	$ 0.32	$ (0.06)
Diluted net (loss) income applicable to common stockholders per common share	$ (0.12)	$ 0.20	$ 0.29	$ (0.06)

Approach Resources Inc.
Index to Exhibits

Exhibit Number	Description of Exhibit
3.1	Restated Certificate of Incorporation of Approach Resources Inc. (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed December 13, 2007 and incorporated herein by reference).
3.2	Restated Bylaws of Approach Resources Inc. (filed as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q filed December 13, 2007 and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512) and incorporated herein by reference).
10.1	Form of Indemnity Agreement between Approach Resources Inc. and each of its directors and officers (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.2	First Amendment to Form of Indemnity Agreement between Approach Resources Inc. and each of its directors and officers (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed December 31, 2008 and incorporated herein by reference).
10.3†	Employment Agreement by and between Approach Resources Inc. and J. Ross Craft dated January 1, 2003 (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-1 filed July 12, 2007 and incorporated herein by reference).
10.4†	First Amendment to Employment Agreement by and between Approach Resources Inc. and J. Ross Craft dated December 31, 2008 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed December 31, 2008 and incorporated herein by reference).
10.5†	Employment Agreement by and between Approach Resources Inc. and Steven P. Smart dated January 1, 2003 (filed as Exhibit 10.4 to the Company's Registration Statement on Form S-1 filed July 12, 2007 and incorporated herein by reference).
10.6†	First Amendment to Employment Agreement by and between Approach Resources Inc. and Steven P. Smart dated December 31, 2008 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed December 31, 2008 and incorporated herein by reference).
*10.7†	Separation Agreement by and between Approach Resources Inc. and Glenn W. Reed dated November 10, 2009.
10.8†	Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1 filed July 12, 2007 and incorporated herein by reference).
10.9†	First Amendment dated December 31, 2008 to Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 31, 2008 and incorporated herein by reference).
10.10	Form of Business Opportunities Agreement among Approach Resources Inc. and the other signatories thereto (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512) and incorporated herein by reference).
10.11†	Form of Option Agreement under 2003 Stock Option Plan (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed July 12, 2007 and incorporated herein by reference).
10.12†	Form of Summary of Stock Option Grant under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512) and incorporated herein by reference).
10.13†	Restricted Stock Award Agreement by and between Approach Resources Inc. and J. Curtis Henderson dated March 14, 2007 (filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1 filed July 12, 2007 and incorporated herein by reference).
10.14†	Form of Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q filed November 6, 2008 and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.15	Registration Rights Agreement dated as of November 14, 2007, by and among Approach Resources Inc. and investors identified therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K/A filed December 3, 2007 and incorporated herein by reference).
10.16	Gas Purchase Contract dated May 1, 2004 between Ozona Pipeline Energy Company, as Buyer, and Approach Resources I, L.P. and certain other parties identified therein (filed as Exhibit 10.18 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.17	Agreement Regarding Gas Purchase Contract dated May 26, 2006 between Ozona Pipeline Energy Company, as Buyer, and Approach Resources I, L.P. and certain other parties identified therein (filed as Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.18	Carry and Earning Agreement dated July 13, 2007 by and between EnCana Oil & Gas (USA) (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.19	Oil & Gas Lease dated February 27, 2007 between the lessors identified therein and Approach Oil & Gas Inc., as successor to Lynx Production Company, Inc. (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.20	Amendment dated as of January 1, 2009, to Oil & Gas Lease dated February 27, 2007 between the lessors identified therein and Approach Oil & Gas Inc., as successor to Lynx Production Company, Inc. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed October 14, 2009 and incorporated herein by reference).
10.21	Specimen Oil and Gas Lease for Boomerang prospect between lessors and Approach Oil & Gas Inc., as successor to The Keeton Group, LLC, as lessee (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.22	Lease Crude Oil Purchase Agreement dated May 1, 2004 by and between ConocoPhillips and Approach Operating LLC (filed as Exhibit 10.26 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512) and incorporated herein by reference).
10.23	Gas Purchase Agreement dated as of November 21, 2007 between WTG Benedum Joint Venture, as Buyer, and Approach Oil & Gas Inc. and Approach Operating, LLC, as Seller (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 28, 2007 and incorporated herein by reference).
10.24	$200,000,000 Revolving Credit Agreement dated as of January 18, 2008 among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, and the financial institutions named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 25, 2008 and incorporated herein by reference).
10.25	Amendment No. 1 dated February 19, 2008 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, as lender, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 22, 2008 and incorporated herein by reference).
10.26	Amendment No. 2 dated May 6, 2008 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, as lender, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K filed August 28, 2008 and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.27	Amendment No. 3 dated August 26, 2008 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 28, 2008 and incorporated herein by reference).
10.28	Amendment No. 4 dated April 8, 2009 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed April 16, 2009 and incorporated herein by reference).
10.29	Amendment No. 5 dated July 8, 2009 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed July 14, 2009 and incorporated herein by reference).
10.30	Amendment No. 6 dated as of October 30, 2009 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 2, 2009 and incorporated herein by reference).
10.31	Amendment No. 7 dated as of February 1, 2010 to Credit Agreement dated as of January 18, 2008 among Approach Resources Inc., as borrower, The Frost National Bank, as agent and lender, JPMorgan Chase Bank, N.A., as successor agent and lender, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 4, 2009 and incorporated herein by reference).
14.1	Code of Conduct (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K filed March 28, 2008 and incorporated herein by reference).
*21.1	Subsidiaries.
*23.1	Consent of Hein & Associates LLP.
*23.2	Consent of DeGolyer and MacNaughton.
*31.1	Certification by the President and Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification by the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification by the Chief Financial Officer Pursuant to U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Report of DeGolyer and MacNaughton.

* Filed herewith.

† Denotes management contract or compensatory plan or arrangement.

Supplemental Non-GAAP Financial Information

Adjusted Net Income

This report contains the non-GAAP financial measures adjusted net income and adjusted net income per diluted share, which exclude the following items:

(i) impairment of long-lived assets,

(ii) unrealized, pre-tax gain or loss on commodity derivatives, and

(iii) related income taxes.

The amounts included in the calculation of adjusted net income and adjusted net income per diluted share below were computed in accordance with GAAP. We believe adjusted net income and adjusted net income per diluted share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table provides a reconciliation of adjusted net income to net (loss) income for the years ended December 31, 2009, 2008 and 2007 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2009	2008	2007
Net (loss) income	$(5,229)	$23,386	$ 2,709
Adjustments for certain non-cash items:			
Impairment of unproved properties	2,964	6,379	267
Impairment of investment	—	917	—
Unrealized loss (gain) on commodity derivatives	9,899	(7,149)	3,637
Related income tax effect	(4,373)	(50)	(1,327)
Adjusted net income	$ 3,261	$23,483	$ 5,286
Adjusted net income per diluted share	$ 0.16	$ 1.13	$ 0.47

EBITDAX

We define EBITDAX as net (loss) income, plus (1) exploration expense, (2) impairment of unproved properties, (3) depletion, depreciation and amortization expense, (4) share-based compensation expense, (5) impairment of investment, (6) unrealized loss (gain) on commodity derivatives, (7) interest expense and (8) income taxes. EBITDAX is not a measure of net income or cash flow as determined by GAAP. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. EBITDAX is presented this report and reconciled to the GAAP measure of net (loss) income because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund development and exploration activities. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table provides a reconciliation of EBITDAX to net (loss) income for the years ended December 31, 2009, 2008 and 2007 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2009	2008	2007
Net (loss) income	$ (5,229)	$23,386	$ 2,709
Exploration	1,621	1,478	883
Impairment of unproved properties	2,964	6,379	267
Depletion, depreciation and amortization	24,660	23,710	13,098
Share-based compensation	1,826	1,100	4,646
Impairment of investment	—	917	—
Unrealized loss (gain) on commodity derivatives	9,899	(7,149)	3,637
Interest expense, net	1,787	1,269	5,219
Income tax (benefit) provision	(785)	12,111	(108)
EBITDAX	$36,743	$63,201	$30,351
EBITDAX per diluted share	$ 1.75	$ 3.03	$ 2.71

Liquidity and Long-Term Debt-to-Capital

Although liquidity and long-term debt-to-capital are not considered non-GAAP financial measures, we provide a summary of our liquidity and long-term debt-to-capital calculations below.

Liquidity is calculated by adding the net funds available under our revolving credit facility and cash and cash equivalents. We use liquidity as an indicator of the Company's ability to fund development and exploration activities. However, this measurement has limitations. This measurement can vary from year to year for the Company and can vary among companies based on what is or is not included in the measurement on a company's financial statements. This measurement is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

Summary of Liquidity Position (In thousands)	December 31, 2009	2008
Borrowing base	$115,000	$100,000
Cash and cash equivalents	2,685	4,077
Long-term debt	(32,319)	(43,537)
Liquidity	$ 85,366	$ 60,540

Long-term debt-to-capital ratio is calculated by dividing long-term debt (GAAP) by the sum of total stockholders' equity (GAAP) and long-term debt (GAAP). We use the long-term debt-to-capital ratio as a measurement of our overall financial leverage. However, this ratio has limitations. This ratio can vary from year to year for the Company and can vary among companies based on what is or is not included in the ratio on a company's financial statements. This ratio is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

2009 Production Replacement

Although production replacement is not considered a non-GAAP financial measure, we provide a summary of our production replacement calculation below.

We use production replacement ratios as an indicator of the Company's potential ability to replace annual production volumes and grow our reserves. However, these production replacement ratios have limitations.

These ratios can vary from year to year for the Company and among other oil and gas companies based on the extent and timing of discoveries and property acquisitions. In addition, since these ratios do not incorporate the cost or timing of future production of new reserves, they should not be used as a measure of value creation.

Production replaced from drilling alone is calculated by dividing extensions and discoveries of 30.4 Bcfe by production of 8.8 Bcfe.

Production replaced from all sources is calculated by dividing net proved reserve additions of 16.7 Bcfe (the sum of extensions and discoveries and revisions) by production of 8.8 Bcfe.

Reserve summary (MMcfe)	
Balance — December 31, 2008	211,068
Extensions and discoveries	30,395
Purchases of minerals in place	—
Production	(8,808)
Revisions to previous estimates	(13,727)
Balance — December 31, 2009	218,928
Production replacement	
Production replaced from drilling alone	345%
Production replaced from all sources	190%

Finding and Development Costs

Drill-bit finding and development ("F&D") costs are calculated by dividing the sum of exploration costs and development costs for the year by the total of reserve extensions and discoveries for the year.

All-in F&D costs, including revisions, are calculated by dividing the sum of property acquisition costs, exploration costs and development costs for the year by the total of reserve extensions, discoveries and all revisions for the year.

All-in F&D costs, including revisions and the change in future development costs, are calculated by dividing the sum of property acquisition costs, exploration costs, development costs and the change in future development costs from the prior year by the total of reserve extensions, discoveries and all revisions for the year.

We believe that providing the above measures of F&D cost is useful to assist in an evaluation of how much it costs the Company, on a per Mcfe basis, to add proved reserves. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes). Due to various factors, including timing differences, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods before the periods in which related increases in reserves are recorded, and development costs may be recorded in periods after the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases (or decreases) in reserves independent of the related costs of such increases.

As a result of the above factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in our filings with the SEC, we cannot assure you that the Company's future F&D costs will not differ materially from those set forth above. Further, the methods used by us to calculate F&D costs may differ significantly from methods used by other companies to compute similar measures. As a result, our F&D costs may not be comparable to similar measures provided by other companies.

The following table reflects the reconciliation of our estimated F&D costs for the year ended December 31, 2009, to the information required by paragraphs 11 and 21 of ASC 932-235:

Cost summary (in thousands)	
Property acquisition costs	
Unproved properties	$ 1,082
Proved properties	57
Exploration costs	1,483
Development costs(1)	28,121
Total costs incurred	$ 30,743
Future development costs (in thousands)	
2008	$201,259
2009	213,161
Change in future development costs	$ 11,902
Reserve summary (MMcfe)	
Balance — December 31, 2008	211,068
Extensions and discoveries	30,395
Purchases of minerals in place	—
Production	(8,808)
Revisions to previous estimates	(13,727)
Balance — December 31, 2009	218,928
Finding and development costs ($/Mcfe)	
Drill-bit F&D cost	$ 0.97
All-in F&D cost, including revisions	$ 1.84
All-in F&D costs, including revisions and change in future development costs	$ 2.56

(1) Includes $170,000 in non-cash asset retirement obligations recorded in 2009.

Corporate Data

BOARD OF DIRECTORS

BRYAN H. LAWRENCE
Chairman of the Board of Directors

J. ROSS CRAFT
President, Chief Executive Officer and Director

JAMES H. BRANDI[1][2]
Director

JAMES C. CRAIN[1][2]
Director, Audit Committee Chairman

SHELDON B. LUBAR[2]
Director, Compensation and Nominating Committee Chairman

CHRISTOPHER J. WHYTE[1]
Director

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[1] Member of the Audit Committee
[2] Member of the Compensation and Nominating Committee

EXECUTIVE OFFICERS

J. ROSS CRAFT
President, Chief Executive Officer and Director

STEVEN P. SMART
Executive Vice President and Chief Financial Officer

J. CURTIS HENDERSON
Executive Vice President and General Counsel

RALPH P. MANOUSHAGIAN
Executive Vice President – Land

QINGMING YANG
Vice President – Exploration

CORPORATE HEADQUARTERS

One Ridgmar Centre
6500 West Freeway, Suite 800
Fort Worth, Texas 76116
817.989.9000 telephone
817.989.9001 facsimile

STOCK LISTING

Approach Resources Inc. is traded on the NASDAQ Global Select Market under the ticker symbol AREX.

INDEPENDENT ACCOUNTANTS

Hein & Associates LLP
Dallas, Texas

OUTSIDE LEGAL COUNSEL

Thompson & Knight LLP
Dallas, Texas

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038
800.937.5449

WEBSITE

www.approachresources.com

A copy of our Annual Report on Form 10-K, as filed with the Securities and Exchange Commission, is available without charge upon request. Please direct your request to Approach Resources Inc., Attention: Corporate Secretary, One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116, 817.989.9000.

Approach
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