fig. 1

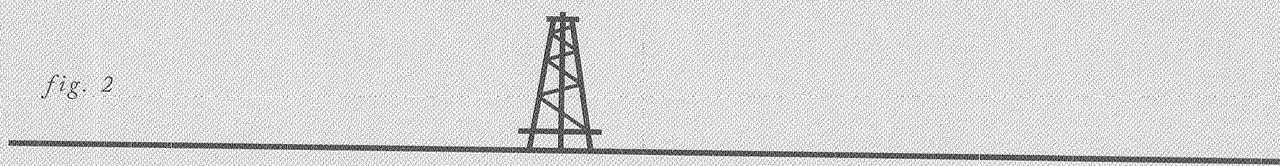
PUSHING *the* BOUNDARIES

APPROACH RESOURCES INC.

2011 annual report

WOLFCAMP

fig. 2



SYSTEM	STRATIGRAPHIC UNIT
Permian	CLEARFORK/ SPRABERRY
	DEAN
	WOLFCAMP
Pennsylvanian	CANYON
	STRAWN
Mississippian	
Devonian	
Silurian	
Ordovician	ELLENBURGER

POTENTIAL HORIZONTAL WOLFCAMP TARGETS

WOLFCAMP A	Pilot
WOLFCAMP B	Transitioning to Development
WOLFCAMP C	Pilot — Recent Results Encouraging
WOLFCAMP D	Under Evaluation

an INTRODUCTION *to the* WOLFCAMP OIL SHALE RESOURCE PLAY

"WE ANNOUNCED OUR GEOLOGICAL AND ENGINEERING ASSESSMENT OF THE WOLFCAMP OIL SHALE RESOURCE PLAY IN OCTOBER 2010, AND BY YEAR-END 2011, THE WOLFCAMP HAS BECOME THE MAIN DRIVER FOR OUR LIQUIDS-WEIGHTED PRODUCTION AND RESERVES GROWTH.

During 2011, we made significant progress with our horizontal and vertical pilot programs, and we are still in the early stage of understanding the potential of this resource. Our team of geoscientists and engineers continues to identify key ways to increase our opportunities in the play, including targeting multiple zones for horizontal drilling within the Wolfcamp Shale, testing the spacing between well locations, and optimizing recovery with advanced completion techniques."

– J. ROSS CRAFT, P.E.
Director, President and
Chief Executive Officer

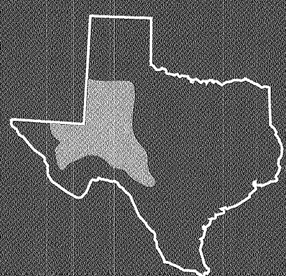
TECHNICAL EVALUATION *is* KEY *to* UNDERSTANDING *the* WOLFCAMP

· High total organic content indicates significant hydrocarbon generating potential
· Thermal maturity suggests peak oil to early wet gas window
· Shale rock properties indicate large storage capacity
· Natural fractures enable stimulation and provide hydrocarbon pathway to wellbore
· Mineral components are favorable for fracture stimulation
· Significant hydrocarbons in place

ABOUT *the* COMPANY

We are an independent energy company headquartered in Fort Worth, Texas. Our strategy is to build long-term stockholder value by exploring and developing oil and gas reserves in oil shale and tight gas sands in the Permian Basin, West Texas. We have amassed over 165,000 gross acres in the Permian Basin, where we target stacked oil and liquids-rich formations at competitive operating and development costs. At December 31, 2011, our proved reserves totaled 77.0 MMBoe, made up of 61% oil and NGLs and 39% natural gas. During 2011, we made significant progress in the Wolfcamp oil shale resource play, increasing production and reserves by 50% or more and leading the way for new opportunities in the Permian Basin, all with an eye on capital discipline. 2011 was a successful year — and we continue to focus on creating stockholder value well into the future.

CORE AREA *of* OPERATION



PERMIAN BASIN - SOUTHERN MIDLAND BASIN

Project Pangea and Pangea West

Stacked targets:

Clearfork, Wolfcamp A-D, Canyon Sands, Strawn, Ellenburger

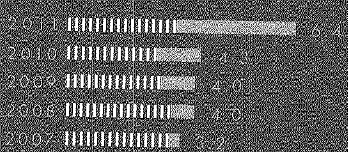
76.8 MMBoe proved reserves

165,700 gross (145,000 net) acres

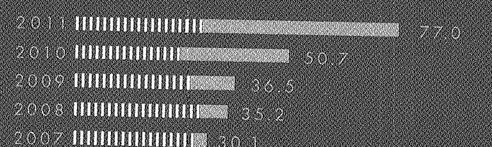
2,900+ potential drilling & recompletion opportunities

PRODUCTION *and* RESERVES

OIL & NGLs NATURAL GAS



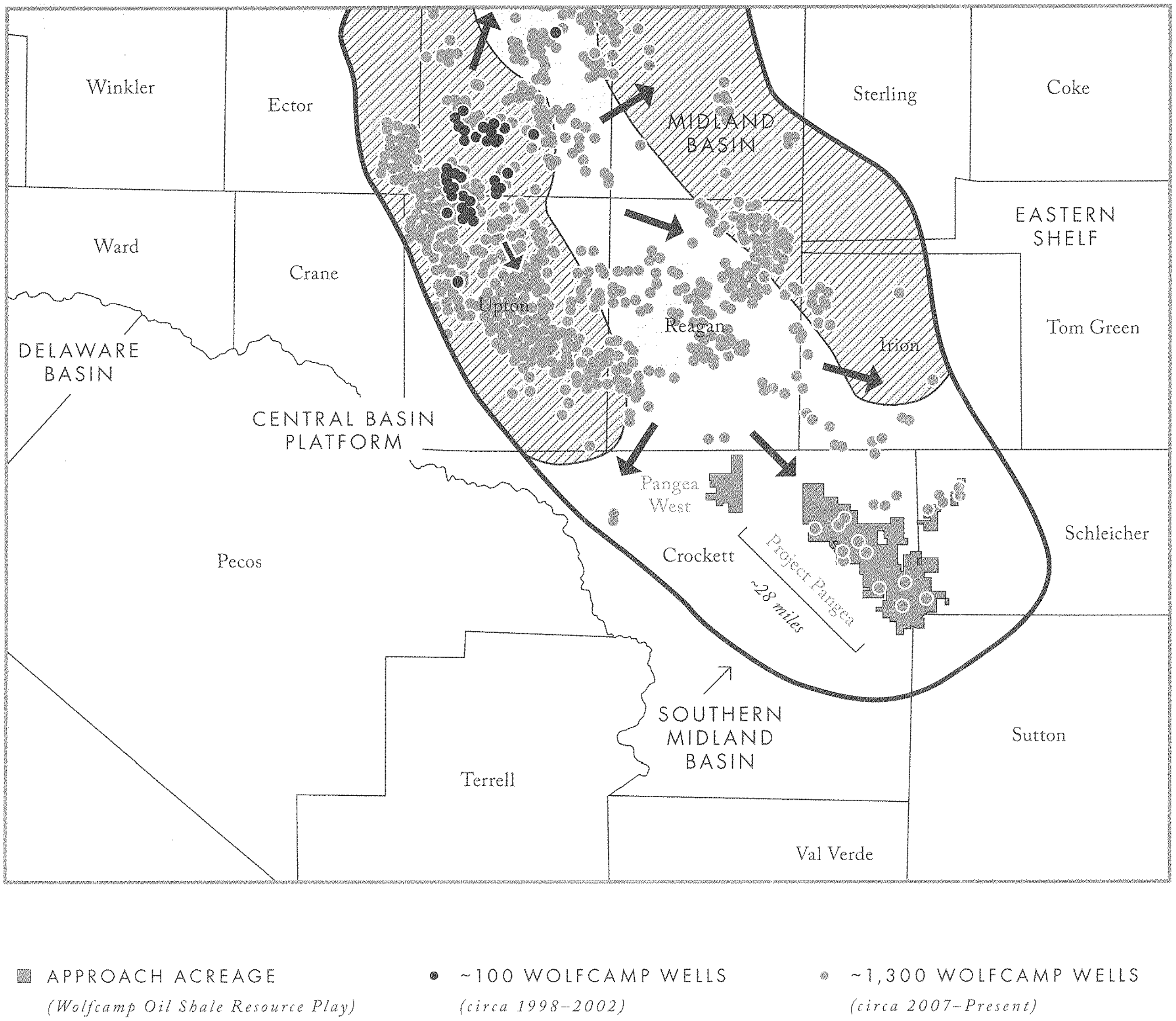
DAILY PRODUCTION
(MBoe/d)



PROVED RESERVES
(MMBoe)

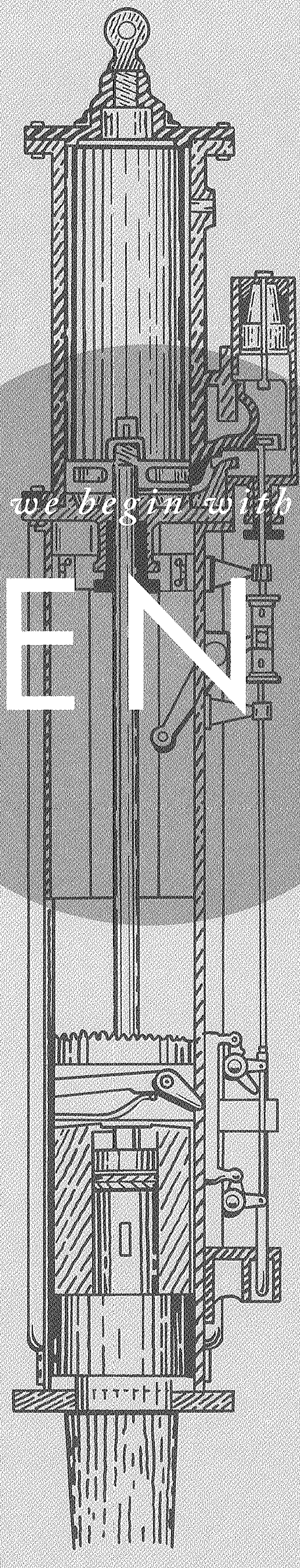
Estimated proved reserves and acreage are as of December 31, 2011. In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in our Annual Report on Form 10-K for the year ended December 31, 2011, which was filed with the Securities and Exchange Commission on March 12, 2012.

fig. 3



APPROACH RESOURCES IS PUSHING THE BOUNDARIES. THROUGH INNOVATIVE THINKING, DETAILED TECHNICAL STUDIES, HORIZONTAL DRILLING AND MULTI-STAGE COMPLETIONS, WE BELIEVE WE HAVE UNCOVERED GREAT POTENTIAL IN THE SOUTHERN MIDLAND BASIN WOLFCAMP. WE ARE HELPING TO SHIFT THE PARADIGM FOR OIL PRODUCTION IN THIS AREA.

fig. 4



we begin with

INGENUITY

INGENUITY

We had a concept, which we refined for over a year before drilling our first well. Our technical evaluation of the Wolfcamp in the Southern Midland Basin led us to an important discovery.

dear fellow shareholders,

THINKING OUTSIDE THE BOX LED OUR TEAM TO UNCOVER A GREAT OPPORTUNITY IN THE WOLFCAMP. A PROLIFIC OIL SHALE RESOURCE PLAY, THE WOLFCAMP IS OUR PRIMARY DRIVER FOR GROWTH IN PRODUCTION, RESERVES AND STOCKHOLDER VALUE.

Thanks to the hard work and innovative thinking of our dedicated team of employees, we have the strongest inventory of resource potential in the company's history. In 2012, we expect this inventory to grow as we further advance our understanding of the horizontal Wolfcamp oil shale play. We've increased our leverage in the play with strategic working interest and acreage acquisitions, and assembled a competitive acreage position in the Southern Midland Basin. Together, our inventory of locations and our acreage position should enable us to grow production and cash flow for years to come.

Over the last two years, our primary focus has been on testing and derisking the Wolfcamp oil shale resource play in the Southern Midland Basin in West Texas. In 2010, we first publicly discussed the significant resource potential of this play. We outlined the geological characteristics and preliminary reserve estimates. Importantly, we also concluded that the Midland Basin extended farther south, beyond the boundaries of conventional thinking about the limits of the Midland Basin. Our initial assessments were met with skepticism, but our team worked hard and delivered strong well results in 2011.

2011 was the year of our pilot drilling programs. We ran two vertical rigs, one horizontal rig and one workover rig for drilling and recompletions in the Clearfork and Wolfcamp zones. By September 2011, we transitioned our vertical pilot program to the development stage. Our team also worked tirelessly to refine our drilling and completion techniques for our horizontal program. Within a few months, we improved our initial production rates more than three times, with an 80% to 90% oil and NGL mix. As a result of strong initial production rates and increased oil and NGL production, the economics of our horizontal Wolfcamp program have gone from acceptable to very attractive despite record low natural gas prices.

The Wolfcamp pay zone is over 1,000 feet thick. We have identified four sub-zones that we refer to simply as Wolfcamp A, B, C and D.

fig. 5
AREX PERMIAN HIGHLIGHTS

6.4
MBoe/d
DAILY PRODUCTION

76.8
MMBoe
PROVED RESERVES

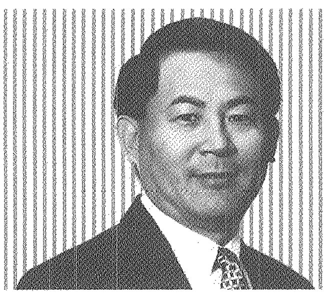
61%
OIL & NGLs

165,700
GROSS ACRES

2,900+
POTENTIAL DRILLING & RECOMPLETION OPPORTUNITIES

fig. 6
APPROACH LEADERSHIP

J. ROSS CRAFT, P.E.
Director, President and Chief Executive Officer



QINGMING YANG
Executive Vice President, Business Development and Geosciences

We focused on the Wolfcamp B zone during 2011, and drilled our first horizontal pilot well in the Wolfcamp B in the first quarter of 2011. By year-end, we had drilled 13 horizontal wells. We believe that ongoing refinements to our completion techniques have significantly improved well performance. Five of our most recent horizontal Wolfcamp wells produced at an average initial rate of approximately 1,000 Boe per day, made up of 85% oil and 93% total liquids. We are still in the early stage of understanding the full resource potential of the horizontal Wolfcamp play, and we believe we've identified key ways to further increase our opportunities in 2012, including testing stacked horizontal wells in the Wolfcamp A, B and C zones and downspacing between well locations, as well as continuing to increase well recovery with our refined completion techniques. So far in 2012, we've tested the Wolfcamp C and are very encouraged by this first pilot well. We plan to drill more wells targeting the Wolfcamp C as well as the Wolfcamp A in 2012.

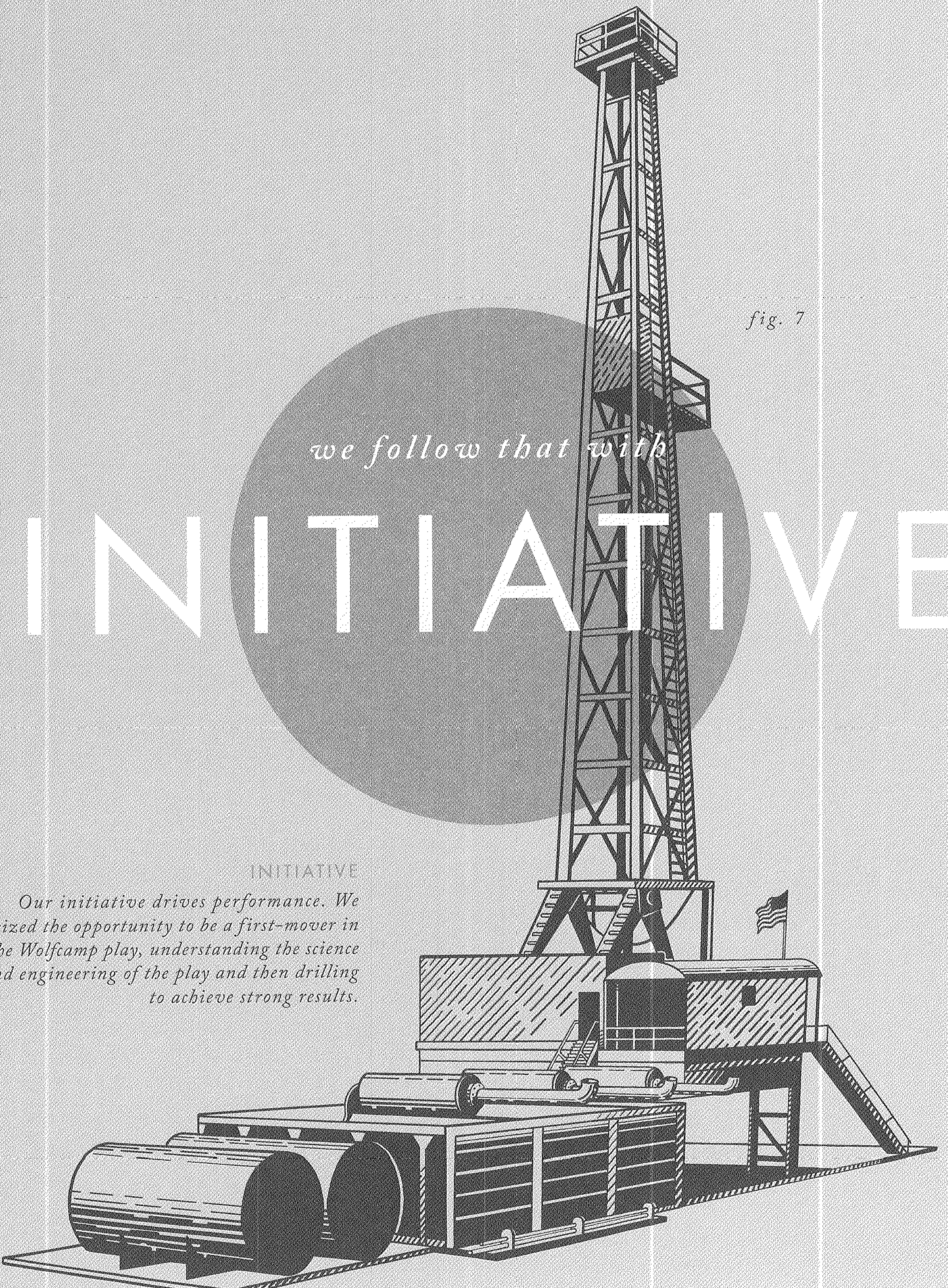
Our pilot program and industry activity confirmed the initial view that we developed in 2009 and first discussed with you in 2010. The Wolfcamp oil shale resource play is thick, naturally fractured and widespread. The horizontal Wolfcamp play may ultimately span more than 2 million acres in the Southern Midland Basin. The industry has quickly turned its attention to this area, and we believe the horizontal Wolfcamp could become one of the largest oil shale resource plays ever discovered onshore in the United States.

During 2011, we increased proved reserves 52% and grew proved oil and NGL reserves 84%.

From the original rollout of our horizontal Wolfcamp play in 2010 to year-end 2011, the Wolfcamp has become the main driver for our liquids-weighted reserve and production growth. During 2011, we increased proved reserves 52% and grew proved oil and NGL reserves 84%. Our reserve mix is now over 60% oil and NGLs, compared to 11% when we went public in 2007. We also increased production in 2011 by 50% over 2010 and 167% over 2007. In 2011, we replaced more than 1,000% of our production at a competitive finding and development cost of $7.54 per Boe.

In 2011, our share price finished up 27%, outperforming the S&P 500 and the Dow Jones U.S.

fig. 7



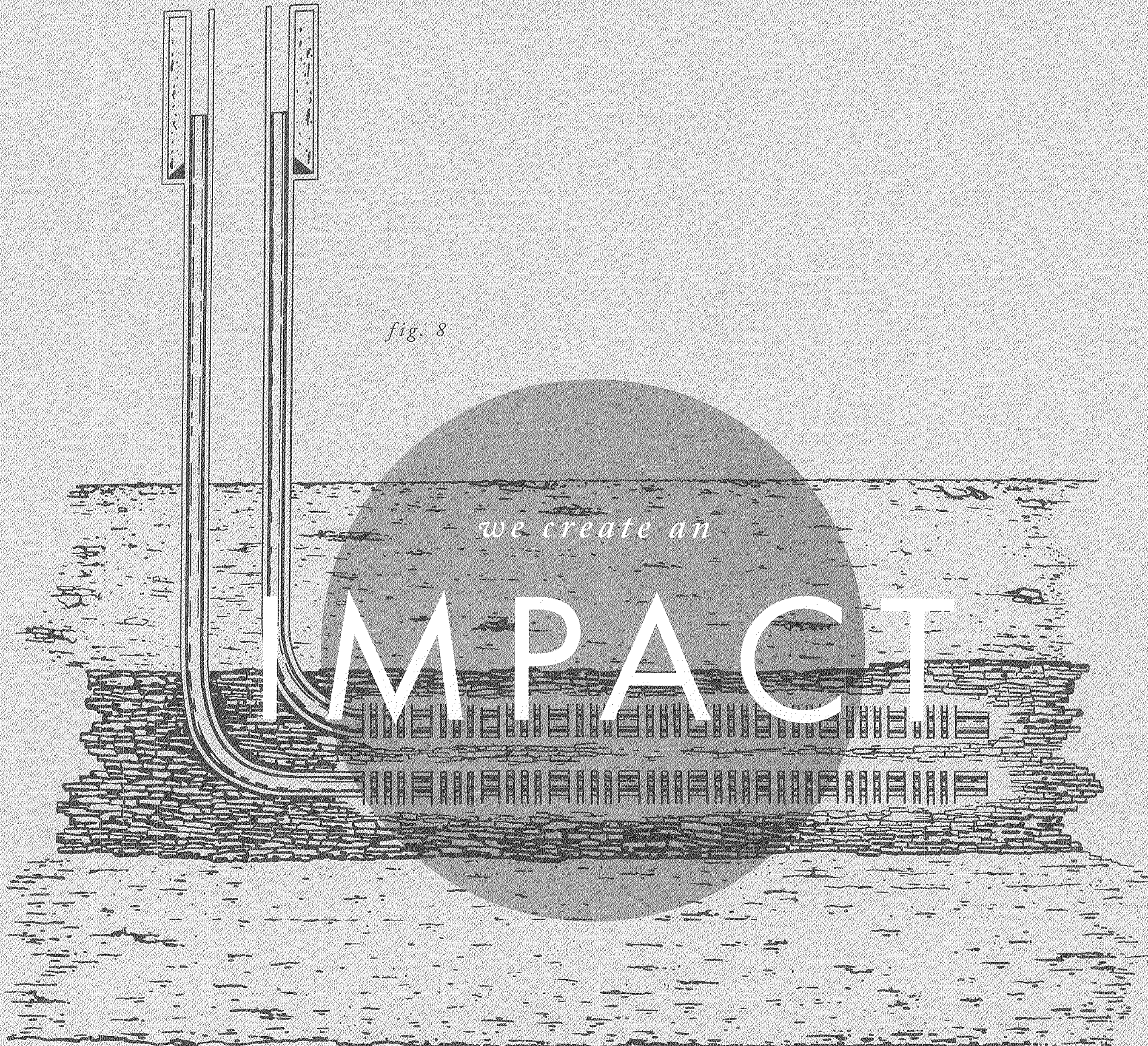
we follow that with

INITIATIVE

INITIATIVE

Our initiative drives performance. We seized the opportunity to be a first-mover in the Wolfcamp play, understanding the science and engineering of the play and then drilling to achieve strong results.

fig. 8



IMPACT

The Wolfcamp's prominence is rising in the Southern Midland Basin. We believe horizontal drilling will enable us to maximize the potential of this significant resource.

Exploration & Production Index. **Over the last three years, we have delivered cumulative total shareholder return of 302%.**

We believe we are well-positioned to deliver successive years of production and reserve growth at competitive finding, development and operating costs.

Financial strength is important to us. We ended 2011 with approximately $43.8 million in borrowings outstanding under our credit facility, and our long-term debt-to-capital ratio was just 8.6%. Our commitment to a strong balance sheet has helped us deliver value and growth to our stockholders in the past, and we believe it will continue to enable us to develop our growing opportunities in 2012 and beyond.

Thus far in 2012, we have added a second horizontal rig due to encouraging results from our horizontal Wolfcamp pilot program. To facilitate future growth, we plan to continue investing in our infrastructure. We are undertaking several field projects, including pipelines to gather our growing liquids production, and water transfer systems to safely and securely transfer water to and from our well sites. In addition, our engineering teams are evaluating the filtering and reuse of completion fluids and non-potable water sources to minimize fresh water use. Through these and other projects we are preparing Project Pangea and Pangea West for full-scale development.

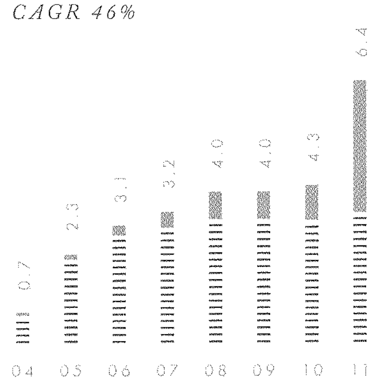
2011 was a transformational year for Approach, marked by a successful pilot program in the Wolfcamp oil shale resource play, significant production and reserve growth, and strong financial performance. We believe we are well-positioned to deliver successive years of production and reserve growth at competitive finding, development and operating costs. During 2011, we were fortunate to have the support of our exceptional employees, business partners and fellow stockholders, and we thank you for your continued support and confidence in Approach Resources.

Sincerely,

J. ROSS CRAFT, P.E.
Director, President and Chief Executive Officer

fig. 9
SOLID TRACK RECORD

AREX GROWTH
CAGR 46%



DAILY PRODUCTION
(MBoe/d)

FINANCIAL & OPERATING DATA *($ in thousands, except per-share and per-unit amounts)*

	2011	2010	2009
REVENUES (IN THOUSANDS)			
Oil	$ 42,463	$ 18,640	$ 11,323
NGLs	41,029	10,765	5,919
Gas	24,895	28,176	23,406
Total oil, NGL and gas sales	108,387	57,581	40,648
Realized gain on commodity derivatives	$ 3,375	$ 5,784	$ 14,659
Total oil, NGL and gas sales including derivative impact	$ 111,762	$ 63,365	$ 55,307
PRODUCTION			
Oil (MBbls)	482	246	206
NGLs (MBbls)	798	261	209
Gas (MMcf)	6,345	6,290	6,320
Total (MBoe)	2,338	1,556	1,468
Total (MBoe/d)	6.4	4.3	4.0
AVERAGE PRICES			
Oil (per Bbl)	$ 88.18	$ 75.67	$ 54.97
NGLs (per Bbl)	51.39	41.19	28.32
Gas (per Mcf)	3.92	4.48	3.70
Total (per Boe)	$ 46.37	$ 37.00	$ 27.69
Realized gain on commodity derivatives (per Boe)	1.44	3.72	9.99
Total including derivative impact (per Boe)	$ 47.81	$ 40.72	$ 37.68
COSTS AND EXPENSES (PER BOE)			
Lease operating	$ 5.70	$ 5.50	$ 5.30
Severance and production taxes	2.48	1.92	1.36
Exploration	4.08	1.66	1.10
Impairment	7.90	1.68	2.02
General and administrative	7.66	7.34	7.23
Depletion, depreciation and amortization	13.89	14.28	16.80
FINANCIAL HIGHLIGHTS			
Net income (loss)	$ 7,242	$ 7,462	$ (5,229)
Earnings (loss) per diluted share	$ 0.25	$ 0.34	$ (0.25)
Adjusted net income	$ 19,501	$ 8,673	$ 3,261
Adjusted earnings per diluted share	$ 0.67	$ 0.39	$ 0.16
EBITDAX	$ 79,411	$ 43,026	$ 36,743
EBITDAX per diluted share	$ 2.72	$ 1.94	$ 1.75
Weighted average diluted shares outstanding	29,159	22,214	20,870
Total long-term debt	$ 43,800	$ —	$ 32,319
Stockholders' equity	$ 467,449	$ 332,946	$ 220,496
Total assets	$ 607,894	$ 413,089	$ 318,926

Adjusted net income, EBITDAX, finding and development costs and production replacement 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 page in the Investor Relations section of our website at www.approachresources.com.

fig. 10

FORM 10-K

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, 2011

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, 2011 was $529.7 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 9, 2012 was 33,308,502.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2012 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. Natural gas is converted throughout this report at a rate of six Mcf of gas to one barrel of oil equivalent ("Boe"). NGLs are converted throughout this report at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil. If you are not familiar with the oil and gas terms or abbreviations used in this report, please refer to the definitions of these terms and abbreviations 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 (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (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," "potential" 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:

- uncertainties in drilling and exploring for and producing oil and gas;
- uncertainty of commodity prices in oil, NGLs and gas;
- overall United States and global economic and financial market conditions;
- domestic and foreign demand and supply for oil, NGLs, gas and the products derived from such hydrocarbons;
- our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
- disruption of credit and capital markets;
- our financial position;
- our cash flow and liquidity;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our gas and NGLs and other processing and transportation considerations, including limited availability of oil hauling trucks in the Permian Basin, our primary operation;
- marketing of oil, NGLs and gas;
- high costs, shortages, delivery delays or unavailability of drilling and completion equipment, materials, labor or other services;
- competition in the oil and gas industry;
- the effects of government regulation and permitting and other legal requirements;
- uncertainty regarding our future operating results;

- interpretation of 3-D seismic data;
- replacing our oil and gas reserves;
- our inability to retain and attract key personnel;
- our business strategy, including our ability to recover oil and gas in place associated with our Wolffork oil resource play in the Permian Basin;
- development of our current asset base or property acquisitions;
- estimated quantities of oil, NGL and gas reserves;
- 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

ITEM 1. *BUSINESS*

General

Approach Resources Inc. is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on oil and gas reserves in oil shale and tight gas sands in the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger), where we lease approximately 145,000 net acres. Our management and technical team have a proven track record of finding and developing reserves through advanced completion, fracturing and drilling techniques. As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At December 31, 2011, our estimated proved reserves were 77.0 million barrels of oil equivalent ("MMBoe"). At such date, approximately 99.7% of our proved reserves were located in the Permian Basin in Crockett and Schleicher Counties, Texas. The remainder of our proved reserves is located in the East Texas Basin in Limestone County, Texas. Important characteristics of our proved reserves at December 31, 2011, include:

- 61% oil and NGLs and 39% natural gas;
- 44% proved developed;
- 100% operated;
- Reserve life of over 33 years based on 2011 production of 2.3 MMBoe;
- Standardized measure of discounted future net cash flows ("Standardized Measure") of $414.4 million; and
- PV-10 of $679.1 million.

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 for future income taxes. Estimated future net revenues are discounted at an annual rate of 10% to determine their present value. PV-10 is a financial measure that is not determined in accordance with accounting principles generally accepted in the United States ("GAAP"), and generally differs from the Standardized Measure, 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, as computed under GAAP. See Item 2. "Properties — Proved Oil and Gas Reserves" for a reconciliation of PV-10 to the Standardized Measure.

At December 31, 2011, we owned working interests in 638 producing oil and gas wells in the Permian Basin, and we had an estimated 3,000 potential drilling locations, of which 395 were proved. We also had an estimated 190 potential Wolffork recompletion opportunities in the Permian Basin, of which four were proved. We also owned working interests in nine producing gas wells in the East Texas Basin.

We were 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, and is now listed on the NASDAQ Global Select Market ("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 goal is to build long-term stockholder value by growing reserves and production in a cost-efficient manner. To accomplish our goal, we plan to carry out a balanced program of (1) developing our core Permian Basin drilling inventory, (2) evaluating and developing our Wolffork oil shale resource play, (3) operating as a low-cost producer, (4) completing strategic, complementary acquisitions and (5) maintaining financial flexibility. The following are key elements of our strategy:

- *Continue to develop our low risk, multi-year drilling inventory.* We believe we have a large inventory of low-risk drilling locations that provide us the ability to continue to increase production and reserves at a competitive cost. Since 2004, we have been operating in the Permian Basin, where we have drilled more than 595 wells and, as of December 31, 2011, lease approximately 145,000 net acres. Focusing on our Permian Basin properties allows us to develop operating, technical and regional expertise important to interpreting geological and operating trends, enhancing production rates, maximizing well recovery and building a low-risk, multi-year drilling inventory.
- *Evaluate and develop our Wolffork oil shale resource play.* We will dedicate substantially all of our 2012 exploration and development drilling budget to the Wolffork oil shale resource play. For 2012, we expect to drill 21 horizontal wells targeting the Wolfcamp Shale and 28 vertical wells targeting the Wolffork and Canyon Sands and recomplete 24 to 48 wells. We have identified approximately 2,955 potential Wolffork drilling and recompletion locations, including:
  - 500 potential horizontal Wolfcamp locations;
  - 1,825 potential vertical Wolffork locations;
  - 440 potential vertical Canyon Wolffork locations; and
  - 190 potential Wolffork recompletions.

  In addition to publicly available well data, we used internal information from cores, 3-D seismic, microseismic, open-hole logging and reservoir engineering to define the extent of targeted intervals, the ability of such intervals to produce commercial quantities of hydrocarbons and the number of potential locations. The timing of drilling our identified potential locations is subject to a number of uncertainties and will be influenced by several factors, including commodity prices, capital requirements, well-spacing requirements and a continuation of the positive results from both our vertical and horizontal drilling program.
- *Operate our properties as a low-cost producer.* We try 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 100% of our reserve base and plan to continue to operate a substantial portion of our producing properties in the future. We believe operating control allows us to better manage timing and risk as well as the cost of exploration and development, drilling and ongoing operations.
- *Acquire strategic, complementary assets.* We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects in our existing core area in the Permian Basin. We focus particularly on opportunities where we believe our operational efficiency, reservoir management and geological expertise in unconventional oil and gas properties will enhance value and performance. We remain focused on unconventional resource opportunities, but will also look at conventional opportunities based on individual project economics.
- *Maintain financial flexibility.* We believe that a strong balance sheet and liquidity provide us with significant financial flexibility to pursue our strategic and financial objectives. Also, we may from time to time enter into commodity price swaps and collars to partially mitigate the risk of commodity price volatility. Furthermore, during times of severe price declines, we may from time to time reduce capital expenditures and curtail drilling to preserve our financial flexibility and the net asset value of our existing proved reserves.

2011 Activity

Our operations are focused on the Permian Basin, where our leasehold position is characterized by multiple oil and liquids-rich formations. Historically, we have focused our drilling on tight gas sands (Canyon Sands) and the Strawn and Ellenburger formations in the Permian Basin. Data from drilling vertical Canyon, Strawn and Ellenburger wells, combined with a detailed geological and petrophysical study, led to our decision to begin to develop the shallower Clearfork and Wolfcamp formations in late 2010. We sometimes refer to the Clearfork and Wolfcamp zones together as the "Wolffork" oil shale resource play, and our drilling program in the Permian Basin as "Project Pangea" and "Pangea West."

Proved Reserves and Production Growth

In 2011, our estimated proved reserves increased 52%, or 26.3 MMBoe, to 77.0 MMBoe from 50.7 MMBoe. Reserve growth in 2011 was driven by results in our Wolffork oil shale resource play as well as the acquisition of additional working interest in northwest Project Pangea.

Production for 2011 totaled 2.3 MMBoe (6.4 MBoe/d), compared to 1.6 MMBoe (4.3 MBoe/d) in 2010, a 50% increase. Production for 2011 was 21% oil, 34% NGLs and 45% natural gas. After the expiration of our prior gas sales contract in April 2011, we began realizing NGL revenues from the liquids-rich gas stream in southeast Project Pangea and our NGL production increased 206% in 2011, compared to 2010. In addition, our continued development of Project Pangea increased oil production 96% in 2011, compared to 2010. On average, we operated two vertical rigs and one horizontal rig in 2011, and drilled a total of 71 gross (66.2 net) wells, of which 18 gross (18 net) were waiting on completion at December 31, 2011. We also recompleted 10 gross (10 net) wells in the Wolffork in 2011.

Liquids-Weighted Reserve Profile

Our proved reserve profile at year end 2011 was 61% oil and NGLs and 39% natural gas, compared to 51% oil and NGLs and 49% natural gas at year end 2010. During 2011, our proved oil and NGL reserves increased 21.6 MMBbls, or 84%, to 47.2 MMBbls from 25.6 MMBbls in 2010. Our increase in proved oil and NGL reserves is primarily due to the liquids-rich production and reserve profile of the Wolffork oil shale resource play and processing upgrades in southeast Project Pangea. On April 1, 2011, we began realizing NGL revenues from the liquids-rich gas stream in southeast Project Pangea.

Working Interest Acquisition

In February 2011, we acquired the remaining 38% working interest in northwest Project Pangea from two non-operating partners for $70.8 million, after customary post-closing adjustments (the "Working Interest Acquisition"). The Working Interest Acquisition was funded with cash on hand and borrowings under our revolving credit facility. As a result of the Working Interest Acquisition, our working and net revenue interests in Project Pangea are approximately 100% and 76%, respectively.

Acquisition of Acreage

We acquired approximately 43,000 net acres in the Permian Basin in Crockett and Schleicher Counties, Texas, during 2011. The acreage acquisitions increased our exposure to the Wolffork oil shale resource play.

2011 Equity Offering

In November 2011, we sold 4.6 million shares of common stock in an underwritten public equity offering at $28 per share (the "2011 Offering"). After deducting underwriting discounts and transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We intend to use the proceeds to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used the proceeds of the 2011 Offering to repay outstanding borrowings under our revolving credit facility.

Plans for 2012

In November 2011, we announced a drilling program that included two rigs to drill vertical wells targeting the Wolffork and Canyon Sands and one rig to drill horizontal wells targeting the Wolfcamp. Due to continued, strong results from our horizontal Wolfcamp drilling program, we replaced one of our vertical drilling rigs with a second horizontal rig in Project Pangea in March 2012. In connection with the expansion of our horizontal Wolfcamp drilling program, our Board of Directors approved a $30 million increase in our 2012 capital budget to $190 million. We also expect to recomplete two to four wells per month in the Wolffork in 2012. Our objectives for 2012 include advancing our understanding of optimal well spacing, testing multi-zone potential and refining recompletion techniques to enhance hydrocarbon recovery in our Wolffork targets and improving our cost structure.

Our 2012 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, NGLs and gas, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Markets and Customers

The revenues generated by our operations are highly dependent upon the prices of, and supply and demand for, oil, NGLs 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 domestic 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.

The following table summarizes the top five purchasers of our oil, NGL and gas sales for 2011, excluding realized commodity derivative settlements.

Purchaser	Percent of Oil, NGL and Gas Sales
Belvan Partners, LP ("WTG")	34.5%
Shell Trading (US) Company ("Shell")	25.0
DCP Midstream, LLC ("DCP")	22.0
Eastex Crude Co. ("Eastex")	6.0
BML, Inc. ("BML")	5.6
Total	93.1%

Commodity Derivative Activity

We enter into financial swaps and options 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 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 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.

Oil and Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 80% to 75%.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and gas industry is highly competitive, and we compete for prospective properties, producing properties, personnel and services 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 end 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. It is not possible to predict whether such legislation or regulation may ultimately be adopted or its precise 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 our operations.

Hydraulic Fracturing

Hydraulic fracturing is an important process and has been commonly used in the completion of unconventional oil and gas wells in shale and tight sand formations since the 1950's. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and gas production. It is important to us because we believe it maximizes the productivity of our oil and gas wells.

We are currently using hydraulic fracturing to complete both vertical and horizontal wells in the Permian Basin. We engage third parties to provide hydraulic fracturing services to us for completion of these wells. While hydraulic fracturing is not required to maintain our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, completion and recompletion projects, or approximately 62% of our total estimated proved reserves as of December 31, 2011, require hydraulic fracturing.

We believe we have followed, and intend to continue to follow, applicable industry standard practices and legal requirements for groundwater protection in our operations that are subject to supervision by state regulators. These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by applicable state regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. We believe we have adequate procedures in place to address abrupt changes to the injection pressure or annular pressure.

Texas regulations currently require disclosure of the components in the solutions used in hydraulic fracturing operations. Over 99% (by mass) of the ingredients we use in hydraulic fracturing are water and sand. The remainder of the ingredients are chemical additives that are managed and used in accordance with applicable requirements.

Hydraulic fracturing requires the use of a significant amount of water. Upon flowback of the water, we dispose of it in a way that we believe minimizes the impact to nearby surface water by disposing into approved disposal facilities or injection wells. We currently are exploring ways to reuse water in our hydraulic fracturing operations.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "Business — Regulation — Environmental Regulation" and "Business — Regulation — Hydraulic Fracturing." For related risks to our stockholders, please read "Risk Factors — Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could stop or delay drilling projects and result in materially increased costs and additional operating restrictions."

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 U.S. Department of Interior, the U.S. Department of Transportation (the "DOT") (Office of Pipeline Safety) and the U.S. Environmental Protection Agency (the "EPA"). 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, penalties or other remedies that are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with federal, state and local rules, regulations and procedures, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations.

Transportation and Sale of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by the Federal Energy Regulation Commission ("FERC") pursuant to the Interstate Commerce Act ("ICA"), Energy Policy Act of 1992 ("EPAct 1992"), and the rules and regulations promulgated under those laws. The ICA and its regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products ("petroleum pipelines"), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are also subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

The transportation of oil by truck is also subject to federal, state and local rules and regulations, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002. Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the DOT.

Transportation and Sale of Natural Gas

FERC regulates interstate gas pipeline transportation rates and service conditions under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. Although FERC does not regulate oil and gas producers such as us, FERC's actions are intended to facilitate increased competition within all phases of the oil and 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 policies have not materially affected our business or operations.

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 state in which we operate, Texas, has 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, Texas imposes a severance tax on production and sales of oil, NGLs and gas within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Laws and 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. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling begins;
- require the installation of expensive pollution controls or emissions monitoring equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, completion, 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. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretations of enforcement policies 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 or results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. 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 environmental laws, rules and regulations that apply to our business operations.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state statutes impose strict liability, 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 ("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 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 water and most of the other wastes associated with the exploration, development 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 increase our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease 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 other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. In particular, on August 23, 2011, pursuant to a court-ordered consent decree, the EPA published a proposed rule establishing new emissions standards to reduce volatile organic compounds ("VOCs") from new sources ("New Source Performance Standards") and sulfur dioxide emissions from several types of processes and equipment used in the oil and gas industry. The proposed rule includes reduced emissions from completions of new, hydraulically fractured gas wells, a 95% reduction in VOCs emitted from some newly constructed or modified oil and condensate vessels, vent rate limits for new or replaced pneumatic devices and part replacement schedules for newly installed natural gas compressors. New Source Performance Standards apply to individual components or facilities, regardless of whether permitting requirements apply. The consent decree requires the EPA to take final action by April 3, 2012. These proposed standards, should they be adopted, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements or use specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission related issues, which could adversely impact our future business, financial condition and results of operations. Obtaining permits also has the potential to delay the development of oil and gas projects. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Greenhouse Gas Emissions

In February 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change (the "Protocol") became effective. Pursuant to the Protocol, adopting countries are required to implement national programs to reduce emissions of greenhouse gasses ("GHGs"), which are suspected of contributing to global warming. The United States is not currently a participant in the Protocol; however, the Protocol has resulted in significant political pressure on the U.S. to take responsive action.

Congress has, from time to time, considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050, but it was not approved by the U.S. Senate. Congress is likely to continue to consider similar bills. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap and trade programs or other mechanisms. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Many states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA has adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule was finalized in April 2010 and became effective in January 2011, but it does not require immediate reductions in GHG emissions. The stationary source rule was adopted in May 2010, became effective in January 2011 and is the subject of several pending lawsuits filed by industry groups. The EPA also plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

In December 2010, the EPA enacted final rules on mandatory reporting of GHGs. Under the final rules, owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalent or CO_2E) would have been required to report carbon dioxide, methane and nitrous oxide emissions, beginning on March 31, 2012. However, in November and December 2011, the EPA published amendments to the rule containing technical and clarifying changes to certain GHG reporting requirements and a six-month extension for reporting GHG emissions from petroleum and natural gas industry sources. Under the amended rule certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities are required to report their GHG emissions on an annual basis beginning on September 28, 2012, for emissions occurring in 2011. Our operations in the Permian Basin will be subject to the EPA's mandatory reporting rules.

The adoption of legislation or regulatory programs to monitor or reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our future business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls on 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.

In October 2011, the EPA announced that it intends to develop national standards for wastewater discharges produced by natural gas extraction from shale and coalbed methane formations. For shale gas wastewater, the EPA will consider imposing pre-treatment standards for discharges to a wastewater treatment facility. Produced and other flowback water from our current operations in the Permian Basin is typically re-injected into underground formations that do not contain potable water. To the extent that re-injection is not available for our operations and discharge to wastewater treatment facilities is required, new standards from the EPA could increase the cost of disposing wastewater in connection with our operations.

The Safe Drinking Water Act, Groundwater Protection and the Underground Injection Control Program

The federal Safe Drinking Water Act ("SDWA") and the Underground Injection Control program (the "UIC program") promulgated under the SDWA and state programs regulate the drilling and operation of salt water disposal wells. The EPA has delegated administration of the UIC program in Texas to the RRC. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and gas drilling, production and related operations may result in fines, penalties and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages and bodily injury.

Hydraulic Fracturing

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons from tight formations, such as shale rock. The process involves the injection of water, sand and chemical additives under pressure into the formation to fracture the surrounding rock and stimulate oil and gas production. The process is typically regulated by state oil and gas commissions, but Congress and the EPA have, from time to time, proposed actions to regulate hydraulic fracturing at the federal level.

The Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. In the past, legislation has been introduced in, but not passed by, Congress that would amend the SDWA to repeal this exemption. If similar legislation were enacted, it could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Future federal legislation could also require the reporting and public disclosure of chemical additives used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemical additives used in the fracturing process could adversely affect groundwater. If federal legislation regulating hydraulic fracturing is adopted in the future, it could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In 2010, the EPA asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC program by posting a requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. Industry groups filed suit challenging the EPA's decision as a "final agency action" and, therefore, in violation of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. In February 2012, the EPA and industry reached a settlement under which EPA will modify the informal policy posted on its website concerning the need for permits under the UIC program. However, the settlement does not reflect agreement on the issue of regulation of hydraulic fracturing under the SDWA, and the EPA's continued assertion of its regulatory authority under the SDWA could result in extensive requirements that could cause additional costs and delays in the hydraulic fracturing process.

In addition to the above actions of the EPA, certain members of the Congress have called upon (i) the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the Securities and Exchange Commission (the "SEC") to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (iii) the Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The SEC has issued subpoenas to certain shale producers requesting information on proved reserve estimates from shale gas wells and the actual productivity of producing shale wells. The media has also reported that the New York attorney general has issued subpoenas to certain oil and gas companies seeking information regarding shale gas wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has also begun a study of the potential environmental impacts of hydraulic fracturing, with initial results of the study expected in late 2012 and final results expected in 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from using hydraulic fracturing. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released its first and second "90-day" reports on August 18, 2011, and November 18, 2011, respectively, proposing recommendations to reduce the potential environmental impacts from shale gas production. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These ongoing or proposed investigations and studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in hydraulic fracturing. For example, pursuant to legislation adopted by the State of Texas in June 2011, the RRC enacted a rule in December 2011, requiring disclosure to the RRC and the public of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, it could become more difficult or costly for us to drill and produce oil and gas from tight formations and become easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to delays, additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and higher costs. These new laws or regulations could cause us to incur substantial delays or suspensions of operations and compliance costs, and could have a material adverse effect on our business, financial condition and results of operations.

Compliance

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 business, 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, 2011. In addition, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital or operating expenditures during 2012. However, the passage of additional or 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.

Threatened and Endangered Species, Migratory Birds and Natural Resources

Various state and federal statues prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties.

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of 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.

Employees

At February 29, 2012, we had 81 full-time employees, 45 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, our 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 and results of operations. In such a case, you may lose all or part of your investment. The risks described below are not the only we face. 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 and results of operations.

Risks Related to the Oil and Gas Industry and Our Business

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

Our future financial condition and results of operations will depend on the success of our drilling, exploration and production activities. These activities are subject to numerous risks beyond our control, including the risk that drilling will not result in economic oil and gas production or increases in reserves. Many factors may curtail, delay or cancel our scheduled drilling projects, including:

- decline in oil and gas prices;
- inadequate capital resources;

- limited transportation services and infrastructure to deliver the oil and gas we produce to market;
- unavailability or high cost of drilling and completion equipment, services or materials, including water, sand or other materials needed for hydraulic fracturing;
- compliance with governmental regulations, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- inability to attract and retain qualified personnel;
- 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.

Oil and gas prices are volatile, and a decline in oil or gas prices could significantly affect our business, financial condition and 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:

- domestic and foreign supply of oil and gas;
- domestic and foreign consumer demand for oil and gas;
- overall United States and global economic conditions;
- commodity processing, gathering and transportation availability and the availability of refining capacity;
- price and availability of alternative fuels;
- price and quantity of foreign imports;
- 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 and gas prices do not necessarily fluctuate in direct relationship to each other. Because 39% of our estimated proved reserves as of December 31, 2011, were gas reserves, our financial results are also sensitive to movements in gas prices. Recent gas prices have been low, and we expect low gas prices to continue. In 2011, NYMEX natural gas prices dropped from a high of $4.85 per MMBtu to a low of $2.99 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 oil and 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 impair our estimated proved reserves and could have a material adverse effect on our business, financial condition and results of operations. Further, if oil, NGL or 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.

Future economic conditions in the U.S. and international markets could materially and adversely affect our business, financial condition and 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, NGL and gas production and lower commodity prices, which will reduce our revenues, cash flows from operations and our profitability.

Our future reserve and production growth is highly dependent on the success of our Wolffork oil shale resource play, which has a limited operational history and is subject to change.

We began drilling wells in the Wolffork play only recently. The wells that have been drilled or recompleted in these areas represent a very small sample of our large acreage position, and we cannot assure you that our new horizontal or vertical wells or recompletions of existing wells will be successful. As of December 31, 2011, we had proved reserves of 24.2 MMBoe attributable to this play. Accordingly, we have limited information on the amount of reserves that will ultimately be recovered from our Wolffork wells. Our drilling plans in the Wolffork are flexible and depend on a number of factors, including the extent to which our initial pilot wells are successful. The determination of whether we continue to drill prospects in the Wolffork will, among other things, depend on any one or a combination of the following factors:

- our ability to determine the most effective and economic fracture stimulation for the Wolffork play;
- the extent of our success in drilling and completing horizontal wells;
- our ability to control costs and manage drilling and completion risks; and
- the costs and availability of drilling and completion services and equipment, particularly fracture stimulation services, equipment and materials.

We continue to gather data about our prospects in the Wolffork play, and it is possible that additional information may cause us to change our drilling schedule or determine that prospects in some portion of our acreage position should not be developed at all.

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development and acquisition activities require substantial capital expenditures. For example, according to our year-end 2011 reserve report, the estimated capital required to develop our current proved oil and gas reserves is $626 million. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings under our credit facility and public equity financings. Future cash flows are subject to a number of variables, including the production from existing wells, prices of oil, gas and NGLs and our success in developing and producing new reserves. We do not expect our cash flow from operations to be sufficient to cover our current expected capital expenditure budget and we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on favorable terms or at all. The failure to obtain additional financing could cause us to scale back our exploration and development operations, which in turn could lead to a decline in our oil and gas production and reserves, and in some areas a loss of properties.

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

Market conditions or the unavailability of satisfactory oil and gas processing and transportation services may hinder our access to oil and gas markets or delay our production or sales. Although currently we control the gathering systems for our operations in the Permian Basin, we do not have such control over the regional or downstream pipelines in and out of the Permian Basin. The availability of a ready market for our oil, NGL and gas production depends on a number of factors, including market demand and the proximity of our reserves to pipelines or trucking and terminal facilities. In addition, the amount of oil, NGLs and gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to 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, NGL and gas that we produce, or we may be required to shut in oil or gas wells or delay initial production until the necessary gathering and transportation systems are available. Any significant curtailment in gathering system, transportation, pipeline capacity or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition and results of operations.

The unavailability or high cost of drilling rigs, equipment, materials, personnel and oilfield services could adversely affect our ability to execute our drilling 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 equipment, oilfield services and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling and completion 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. Our primary area of operation, the Permian Basin, continues to experience increased demand for drilling rigs, fracture stimulation crews, materials and services, and the availability of such crews, materials and services has been severely restricted. If the availability of equipment, crews, materials and services in the Permian Basin remains particularly severe, our business, results of operations and financial condition could be materially and adversely affected because our operations and properties are concentrated in the Permian Basin.

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, consummate transactions and hire and retain qualified personnel 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 oil, NGLs and gas, attracting and retaining qualified personnel and raising additional capital.

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

Our oil and gas drilling, production and gathering operations are subject to complex and stringent laws and regulations. To operate in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to comply with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations apply to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by government authorities, could have a material adverse effect on our business, financial condition and results of operations. See "Business — Regulation" for a further description of the laws and regulations that affect us.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could stop or delay drilling projects and result in materially increased costs and additional operating restrictions.

Hydraulic fracturing is a practice that is used to stimulate production of oil and gas from tight formations, such as shale rock. The process involves the injection of water, sand and chemical additives under pressure into the formation to fracture the surrounding rock and stimulate production. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling and recompletion projects, or approximately 62% of our total estimated proved reserves as of December 31, 2011, will require hydraulic fracturing. See Item 1. " Business — Hydraulic Fracturing" for a discussion of the importance of hydraulic fracturing to our business, and Item 1. " Business — Regulation — Hydraulic Fracturing" for a discussion of regulatory developments regarding hydraulic fracturing. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to permitting delays and increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. In addition, if we are unable to use hydraulic fracturing in completing our wells or the hydraulic fracturing process becomes prohibited or significantly regulated or restricted, we could lose the ability to drill and complete the projects for our proved reserves, and maintain our current leasehold acreage, which would have a material adverse effect on our future business, financial condition and operating results.

Our ability to produce oil and gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our hydraulic fracturing operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental laws, rules and regulations.

The hydraulic fracturing process that we use to produce oil and gas from the Wolffork oil shale play in the Permian Basin requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in this region. Moreover, new environmental initiatives and regulations could include restrictions on disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Compliance with environmental regulations and permit requirements for the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of our wells may increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which could have an adverse effect on our business, financial condition, results of operations and cash flows.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and gas we produce.

Both houses of Congress have actively considered legislation to reduce emissions of GHGs, and some states have already taken measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs require either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances are expected to escalate significantly in cost over time.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule was finalized in April 2010 and became effective in January 2011 but it does not require immediate reductions in GHG emissions. The stationary source rule was adopted in May 2010 and also became effective January 2011 and is the subject of several pending lawsuits filed by industry groups. The EPA also plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have a material adverse effect on our business, financial condition and results of operations.

Environmental laws and regulations 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, often by third parties not under our control. Private parties, including the owners of properties where 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 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.

Our identified potential drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. In certain instances, this could prevent drilling and production before the expiration date of leases for such locations.

Our management team has identified potential drilling locations as an estimation of our future drilling activities on our existing acreage. These potential drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these potential drilling locations depends on a number of uncertainties, including oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system, marketing and transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

The use of geoscientific, petrophysical and engineering 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 targeting Wolffork and other zones in the Permian Basin and other areas depend on data obtained through geoscientific, petrophysical and engineering analyses, the results of which can be uncertain. Even when properly used and interpreted, data from whole cores, regional well log analyses and 3-D seismic only assist our technical team in identifying hydrocarbon indicators and subsurface structures and estimating hydrocarbons in place. They do not allow us to know conclusively the amount of hydrocarbons in place and if those hydrocarbons are producible economically. In addition, the use of advanced drilling and completion technologies for our Wolffork development, such as horizontal drilling and multi-stage fracture stimulations, requires greater expenditures than our traditional development drilling strategies. Our ability to commercially recover and produce the hydrocarbons that we believe are in place and attributable to the Wolffork and other zones will depend on the effective use of advanced drilling and completion techniques, the scope of our drilling program (which will be directly affected by the availability of capital), drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and geological and mechanical factors affecting recovery rates. Our estimates of unproved reserves, estimated ultimate recoveries per well, hydrocarbons in place and resource potential may change significantly as development of our oil and gas assets provides additional data.

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 production, revenues 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 limited 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.

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

As of December 31, 2011, 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 2012 and 2016. If these leases or options expire, we will lose our right to develop the related properties. See Item 2. "Properties — Undeveloped Acreage Expirations" for a table summarizing the expiration schedule of our undeveloped acreage over the next three years.

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, NGL and gas reserves data included in this report are 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, NGL 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, NGL and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserves 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, NGL and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil, NGL and gas prices.

As of December 31, 2011, approximately 56% 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 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 oil, NGL and gas prices decline by 10% from $96.22 per Bbl of oil, $49.63 per Bbl of NGLs and $4.12 per MMBtu of gas, to $86.60 per Bbl of oil, $44.67 per Bbl of NGLs and $3.71 per MMBtu of gas, then our PV-10 as of December 31, 2011, would decrease from $679.1 million to $537.3 million. The average market price received for our production for the month of December 2011 was $90.35 per Bbl of oil, $50.01 per Bbl of NGLs and $3.11 per Mcf of gas (after basis differential and Btu adjustments). 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.

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. In January 2011, we entered into amended and restated employment agreements with J. Ross Craft, P.E., our President and Chief Executive Officer; and Steven P. Smart, our Executive Vice President and Chief Financial Officer; and new employment agreements with Qingming Yang, our Executive Vice President — Business Development and Geosciences; J. Curtis Henderson, our Executive Vice President and General Counsel; and Ralph P. Manoushagian, our Executive Vice President — Land. If any 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.

If gas prices remain low or decline further, or if oil and NGL prices decline, we may be required to write down the carrying values of our properties. Current SEC rules also could require us to write down our proved undeveloped reserves in the future.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down is a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. In addition, current SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years. Such a write-down could result in a non-cash charge to earnings that could be material to our results of operations for the period in which the charge is taken. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required timeframe.

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 and 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.

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

At December 31, 2011, we had $43.8 million outstanding under our revolving credit facility, and our borrowing base was $260 million. The borrowing base under our revolving credit facility is redetermined semi-annually 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, development and acquisition 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.

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 production, we enter into oil, NGL and gas price and basis differential commodity derivative agreements. While intended to reduce the effects of volatile commodity prices and basis differentials, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the commodity derivative, or if the basis spread changes 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 change 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.

The derivatives reform legislation adopted by Congress could have a material adverse impact on our ability to hedge commodity price risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), was signed into law on July 21, 2010, and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment, though final rules have yet to be issued. In its rulemaking under Dodd-Frank, the CFTC has proposed regulations to set position limits for certain futures and options contracts and swaps in the major energy markets. Certain bona fide hedging transactions or positions would be exempt from these position limits. In December 2011, the CFTC extended the potential expiration date of the exemptive relief to July 16, 2012. It is not possible at this time to predict when the CFTC will finalize these regulations. Dodd-Frank may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us is uncertain at this time. Dodd-Frank may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivatives contracts (including requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against commodity price risks, reduce our ability to monetize or restructure our existing derivatives contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of Dodd-Frank and its regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could therefore be adversely affected if a consequence of Dodd-Frank and its regulations is to lower our realized commodity prices. Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

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

The President's proposed budget for fiscal year 2013 contains 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 gas exploration and production companies. These changes include, but are not limited to, (i) repeal of the percentage depletion allowance for oil and gas properties; (ii) elimination of current deductions for intangible drilling costs; (iii) elimination of the deduction for certain U.S. production activities; and (iv) 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 gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

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

Substantially all of our producing properties and estimated proved reserves are concentrated in two counties in Texas, Crockett and Schleicher. As a result of this concentration, we are disproportionately exposed to the natural decline of production from these fields 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, service delays, natural disasters or other events that impact this area.

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

In 2011, WTG, Shell, DCP, Eastex and BML collectively accounted for 93.1% of our total oil, NGL and gas sales, excluding realized commodity derivative settlements. To the extent that any of our major purchasers reduces their purchases of oil, NGLs or gas or defaults on their obligations to us, we would be adversely affected unless we were able to make comparably favorable arrangements with other purchasers. 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 more of these customers, or due to circumstances related to other market participants with which the customer has a direct or indirect relationship.

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 producing wells or facilities;
- inability to deliver materials to jobsites in accordance with contract schedules; and
- loss of production.

Operating hazards 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. 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, NGL and gas prices, variations in levels of production and the completion of exploration and production projects.

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 gas industry. If any such business opportunity is presented to a Designated Party 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.

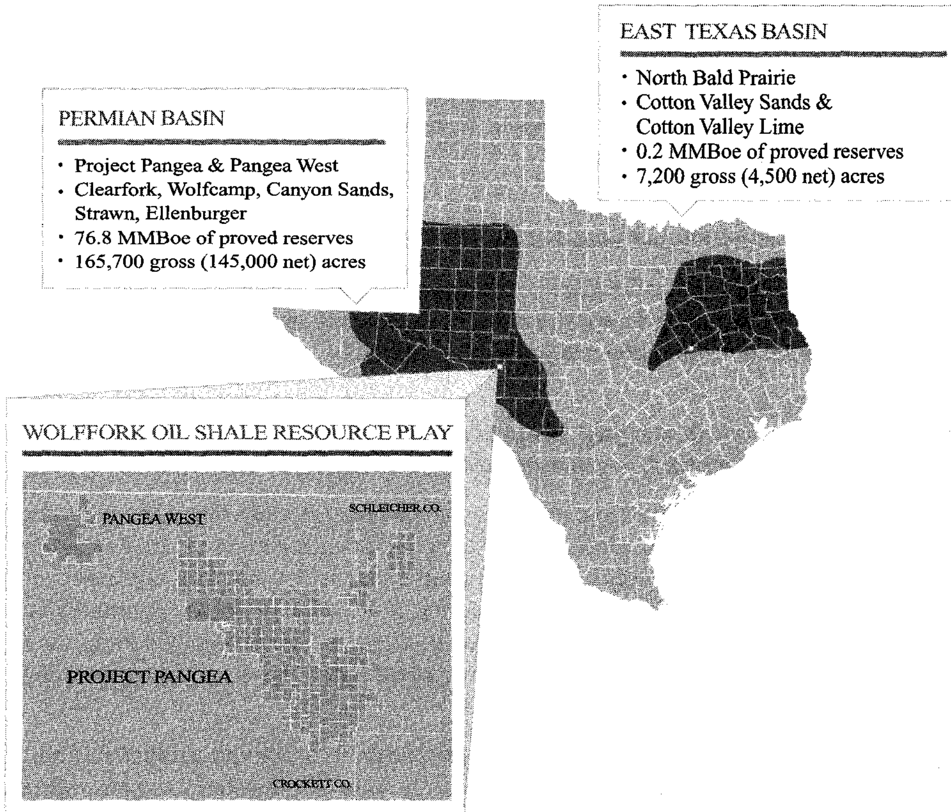
As a result of this renunciation, our outside directors should not be deemed to have breached any fiduciary duty to us if they or their affiliates or associates pursue opportunities as described above and our future competitive position and growth potential could be adversely affected.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

As of the date of this filing, we have no unresolved comments from the staff of the SEC.

ITEM 2. *PROPERTIES*

The following map is an overview of our operating areas and the geologic basins where we operated in Texas at December 31, 2011.



The following table is a summary of data for our operating areas for the year ended December 31, 2011.

Operating Area	Average Daily Production (Boe/d)	Total Production (MBoe)	Percentage of Production	Proved Reserves (MBoe)	Percentage of Proved Reserves
Permian Basin	6,335	2,313	99%	76,763	99.7%
East Texas Basin	69	25	1%	212	0.3%
Total	6,404	2,338	100%	76,975	100%

Permian Basin — Project Pangea and Pangea West

Clearfork, Wolfcamp, Canyon Sands, Strawn and Ellenburger

Our properties in the Permian Basin are located in Crockett and Schleicher Counties, Texas. We began operations in the Permian Basin through a farm-in agreement for 27,000 net acres in 2004, and have since increased our total acreage position to approximately 165,700 gross (145,000 net) acres as of year end 2011. At December 31, 2011, we owned interests in approximately 638 gross (626 net) wells, all of which we operate. As of December 31, 2011, we had working and net revenue interests of approximately 100% and 76%, respectively, across Project Pangea and Pangea West.

Since we began drilling our Permian Basin properties in 2004, we have primarily produced our reserves from the Canyon Sands, Strawn and Ellenburger formations at depths ranging from 7,250 feet to 8,900 feet. The Canyon Sands were deposited in submarine fan and are tight sandstone reservoirs characterized by low permeability. We use a specialized foamed fracture stimulation treatment to increase permeability, which enhances production rates and well recovery. The Strawn formation is a fractured carbonate reservoir between the Canyon Sands and Ellenburger zones. The Ellenburger formation is a fractured carbonate and dolomite reservoir that does not require a specialized fracture stimulation treatment.

As of December 31, 2011, we had estimated proved reserves of 76.8 MMBoe in the Permian Basin, made up of 61% oil and NGLs and 39% natural gas. Our Permian proved reserves increased 59%, and oil and NGL proved reserves increased 84%, over year-end 2010. Reserve growth in 2011 was driven by results in our Wolffork oil shale resource play as well as the acquisition of additional working interest in northwest Project Pangea.

During 2011 in the Permian Basin, we incurred $192 million to drill 71 gross (66.2 net) wells, of which 18 gross (18 net) wells were waiting on completion at December 31, 2011.

Wolffork Oil Shale Resource Play

As mentioned above, since we began drilling our Permian Basin properties in 2004, we have primarily produced our reserves from the Canyon Sands, Strawn and Ellenburger formations at depths ranging from 7,250 feet to 8,900 feet. While we targeted these deeper zones, we collected log data, including mud logs that indicated the presence of hydrocarbons in the Clearfork and Wolfcamp Shale formations, or "Wolffork," above the Canyon Sands, Strawn and Ellenburger zones.

In 2010, we performed a detailed geological and petrophysical evaluation of the Wolffork formations using logs, 3-D seismic, whole core data and regional mapping. The Wolffork is made up of three stacked pay zones, the Clearfork, Dean and Wolfcamp Shale formations with combined gross pay thickness of approximately 2,500 feet. We believe Wolfcamp Shale is a source rock with significant potential for hydrocarbons, located in the oil-to-wet gas window across our Permian acreage position, and is naturally fractured due to its proximity to the Ouachita-Marathon thrust belt and mineralogy, specifically the carbonate and quartz minerals. The Wolfcamp Shale has gross pay thickness of approximately 1,000 feet across our acreage position. The Clearfork formation across our acreage position is a siltstone, shale and carbonate reservoir approximately 1,400 feet thick. Similarly, the Dean formation, which is approximately 150 feet thick, is a siltstone, shale and carbonate reservoir. The Wolffork formations were deposited across Project Pangea and Pangea West by a combination of suspension, debris flow and turbidite processes.

We have identified approximately 2,955 potential drilling and recompletion locations targeting the Wolffork zones, 106 of which are proved, including:

- 500 potential horizontal Wolfcamp locations;
- 1,825 potential vertical Wolffork locations;
- 440 potential vertical Canyon Wolffork locations; and
- 190 potential Wolffork recompletions.

We also have identified 293 proved drilling locations targeting the Canyon Sands and deeper zones. The timing of drilling our identified potential locations is subject to a number of uncertainties and will be influenced by several factors, including commodity prices, capital requirements, well-spacing requirements and a continuation of the positive results from both our vertical and horizontal drilling program.

In the Permian Basin, we consider the Wolffork interval (made up of multiple producing formations, including the Wolfcamp formation) to be a resource play. As such, the mapping of the gross interval for each of the producing formations under our acreage position is the main factor we considered in identifying our potential locations. In the general region and immediately around our acreage position, publicly available well data exists from a large number of vertical wells that have allowed us to define the areal extent of each of the producing intervals, whether the whole vertical Wolffork section or the targeted Clearfork and Wolfcamp Shales. In addition to this publicly available well data, we have also used internally generated information from cores, 3-D seismic, open-hole logging and reservoir engineering to estimate the extent of the targeted intervals, the ability of such intervals to produce commercial quantities of hydrocarbons and the viability of the potential locations. The timing of drilling the identified potential Permian locations will be influenced by several factors, including commodity prices, capital requirements, RRC well-spacing requirements and a continuation of the positive results from both our horizontal and vertical drilling programs.

East Texas Basin — North Bald Prairie

Cotton Valley Sands and Cotton Valley Lime

In July 2007, we entered into a joint drilling venture with EnCana Oil & Gas (USA) Inc. ("EnCana") in Limestone and Robertson Counties, Texas, in the East Texas Cotton Valley trend. We began drilling operations in August 2007. We have 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 in the approximately 7,200 gross (4,500 net) acre project. As of December 31, 2011, we had estimated proved reserves of 1.3 Bcf in North Bald Prairie. Average daily production in 2011 was 0.4 MMcf/d, or a total of 151 MMcf.

Our primary targets in North Bald Prairie are the Cotton Valley Sands and Cotton Valley Lime. These are unconventional tight gas formations where we believe we can apply our geological, technical and operational expertise to improve production and recovery rates. Secondary targets include the shallower Rodessa, Pettit and Travis Peak formations. We currently have no rigs running in North Bald Prairie.

Due to low natural gas prices, we continue to direct our capital expenditures to our assets in the Permian Basin, where we target multiple, liquids-rich zones. As a result, at December 31, 2011, we did not expect to develop the proved undeveloped reserves in North Bald Prairie by year end 2013. Therefore, we reclassified approximately 12.8 Bcf of proved undeveloped reserves as probable undeveloped. We also recorded a non-cash impairment charge to our proved properties in the East Texas Basin of $15.2 million in 2011. At December 31, 2011, we had $2.7 million recorded for our proved properties in the East Texas Basin, which is the estimated fair value at December 31, 2011.

Proved Oil and Gas Reserves

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2011. See Note 10 to our consolidated financial statements in this report for additional information. Our estimated total proved reserves of oil, NGLs and natural gas as of December 31, 2011, were 77.0 MMBoe, made up of 61% oil and NGLs and 39% natural gas. The proved developed portion of total proved reserves at year end 2011 was 44%. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent ("Boe"). NGLs are converted at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil.

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

	Reserves				
Reserves Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Percent (%)
Proved Developed					
Permian Basin	5,542	13,945	83,469	33,399	43.4%
East Texas Basin	—	—	1,274	212	0.3
Proved Undeveloped					
Permian Basin	12,509	15,178	94,064	43,364	56.3
Total Proved Reserves	18,051	29,123	178,807	76,975	100.0%

The following table sets forth our estimated proved reserves, PV-10 and a reconciliation of PV-10 to the Standardized Measure at December 31, 2011. Our reserve estimates and our calculation of Standardized Measure and PV-10 are based on the 12-month average of the first-day-of-the-month pricing of $96.22 per Bbl West Texas Intermediate posted oil price, $49.63 per Bbl received for NGLs and $4.12 per MMBtu Henry Hub spot natural gas price during 2011. All prices were adjusted for energy content, quality and basis differentials by area and were held constant through the lives of the properties.

	December 31, 2011				
Operating Area	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)**	**PV-10**
					(in millions)
Permian Basin	18,051	29,123	177,533	76,763	$ 677,648
East Texas Basin	—	—	1,274	212	1,476
Total	18,051	29,123	178,807	76,975	679,124
Present value of future income tax discounted at 10%					(264,743)
Standardized measure of discounted future net cash flows					$ 414,381

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, 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 as computed under GAAP.

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 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.

Changes to Proved Reserves

The following table sets forth the changes in our proved reserve volumes by operating area during the year ended December 31, 2011 (in MBoe).

Operating Area	**Production**	**Extensions and Discoveries**	**Purchases of Minerals in Place**	**Revisions to Previous Estimates**
Permian Basin	(2,313)	25,548	10,498	(5,248)
East Texas Basin	(25)	—	—	(2,200)
Total	(2,338)	25,548	10,498	(7,448)

We produced 2.3 MMBoe during 2011, 99% of which is attributable to our assets in the Permian Basin. Extensions and discoveries for 2011 of 25.5 MMBoe include 24.2 MMBoe attributable to our Wolffork oil shale resource play in the Permian Basin. During 2011, we purchased approximately 10.5 MMBoe of proved reserves through the Working Interest Acquisition. We also recorded downward revisions in 2011 of 7.5 MMBoe, including 5.6 MMBoe in southeast Project Pangea and 2.2 MMBoe in East Texas, partially offset by 0.3 MMBoe of positive oil and NGL price revisions.

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 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)" promulgated by the Society of Petroleum Engineers ("SPE standards"). Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operations team. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with our internal staff of operations engineers and geoscience professionals and with accounting employees to obtain the necessary data for the reserves estimation process. Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

Our Director of Reservoir Engineering, Mike E. Williams, 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 SPE standards. Mr. Williams has a Bachelor of Science degree in Chemical Engineering from University of Mississippi and over 10 years of industry experience. Mr. Williams 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. Our Chief Executive Officer, J. Ross Craft, P.E., is a licensed Professional Engineer with a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University and over 30 years of industry experience. Our Chief Financial Officer, Steven P. Smart, is a licensed Certified Public Accountant with over 30 years of industry experience.

For the years ended December 31, 2011, 2010, and 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 2011, DeGolyer and MacNaughton reported to the Reserves Subcommittee of the Audit Committee of our Board of Directors and to our Director of Reservoir Engineering. The Reserves Subcommittee meets with the independent engineering firm before the preparation of the firm's final report to, among other things, review and consider the processes used by the engineers in the preparation of the report and any matters of importance that arose in the preparation of the report, including whether the independent engineering firm encountered any material problems or difficulties in the preparation of their report. The Reserves Subcommittee's review specifically includes difficulties with the scope or timeliness of the information furnished to them by the Company or any restrictions or access to information placed upon them by any Company personnel, any other difficulties in dealing with any Company personnel in the preparation of the report and any other matters of concern relating to the preparation of the report. The Reserves Subcommittee also determines whether the Company or its management or senior engineering personnel had similar or other problems or concerns regarding the independent engineering firm and the preparation of their report. See *Third Party Reports* below for further information regarding DeGolyer and MacNaughton's report.

Technologies Used in Preparation of Proved Reserves Estimates

Estimates of reserves were prepared in compliance with SEC rules, regulations and guidance and SPE standards. 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. For our properties, structure and isopach maps were constructed to delineate each reservoir. Electrical logs, radioactivity logs, seismic data and other available data were used to prepare these maps. Parameters of area, porosity, and water saturation were estimated and applied to the isopach maps to obtain estimates of original oil in place or original gas in place. For developed producing wells whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were determined using decline curve analysis. Reserves for producing wells whose performance was not yet established and for undeveloped locations were estimated using type curves. The parameters needed to develop these type curves such as initial decline rate, "b" factor and final decline rate were based on nearby wells producing from the same reservoir and of similar completion for which more data were available.

Reporting of Natural Gas Liquids ("NGLs")

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2011, NGLs represented approximately 38% of our total proved reserves on a Boe basis. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we include these volumes and production as Boe. The prices we received for a standard barrel of NGLs in 2011 averaged approximately 42% lower than the average prices for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs.

Third Party Reports

For the years ended December 31, 2011, 2010, and 2009, 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, including 100% of our total reported proved reserves. DeGolyer and MacNaughton's report for 2011 is included as Exhibit 99.1 to this annual report on Form 10-K.

Proved Undeveloped Reserves

As of December 31, 2011, we had 43.4 MMBoe of proved undeveloped reserves ("PUDs"), which is an increase of 18.5 MMBoe or 74%, compared with 24.9 MMBoe of PUDs at December 31, 2010. At year end 2011, we reclassified 2.2 MMBoe of PUDs as probable undeveloped in the East Texas Basin that, given low natural gas prices, we do not expect to develop by year-end 2013. As a result, all of our PUDs at December 31, 2011, were associated with our core development properties in the Permian Basin. As a percent of our total proved reserves, our PUDs increased from 49% in 2010 to 56% in 2011 due to our ongoing development of our Wolffork oil shale resource play.

The following table sets forth our PUDs converted to proved developed reserves during 2011, 2010 and 2009 and the net investment required to convert PUDs to proved developed reserves during the year (dollars in thousands).

	Proved Undeveloped Reserves Converted to Proved Developed Reserves					
Year Ended December 31,	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)**	**Percent of Total PUDs Converted**	**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**
2009	60	60	1,131	308	1.7%	$ 4,314
2010	589	2,134	12,728	4,845	23.2	37,070
2011	263	660	3,583	1,520	6.1	33,783
Total	912	2,854	17,442	6,673	36.8%	$75,167

Estimated future development costs relating to the development of PUDs are projected to be approximately $159 million in 2012, $215 million in 2013 and $102 million in 2014. We monitor fluctuations in commodity prices, drilling and completion costs, operating expenses and drilling success to determine adjustments to our drilling and development program. Based on current expectations for cash flows, commodity prices and operating costs and expenses, all PUDs are scheduled to be drilled before the end of 2016.

We have 8.9 MMBoe of PUDs, or approximately 11.6% of our total proved reserves, that have been booked for five years or longer. These reserves are located in southeast Project Pangea, where we drilled five gross (five net) wells in 2011 and plan to recomplete six gross (six net) vertical wells targeting the Wolffork in 2012. Despite the continued development drilling in southeast Project Pangea in 2011 and 2012, the volume of PUDs in southeast Project Pangea that will have been booked for five years or longer at December 31, 2012, may increase from December 31, 2011, and, depending on the timing and selection of locations to be drilled in southeast Project Pangea in 2012, such increase might be material. We have a history of significant development activity in southeast Project Pangea, as we have drilled approximately 350 gross (330 net) wells there since our first well in February 2004, and we intend to continue the development of PUDs in southeast Project Pangea over time.

Oil and Gas Production, Production Prices and Production Costs

The following table sets forth summary information regarding oil, NGL and gas production, average sales prices and average production costs for the last three years. We determined the Boe using the ratio of six Mcf of natural gas to one Boe, and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas or NGLs may differ significantly from the price for a barrel of oil.

	Years Ended December 31,		
	2011	2010	2009
Production			
Oil (MBbls)	482	246	206
NGLs (MBbls)	798	261	209
Gas (MMcf)	6,345	6,290	6,320
Total (MBoe)	2,338	1,556	1,468
Total (MBoe/d)	6.4	4.3	4.0
Average prices			
Oil (per Bbl)	$88.18	$75.67	$54.97
NGLs (per Bbl)	51.39	41.19	28.32
Gas (per Mcf)	3.92	4.48	3.70
Total (per Boe)	46.37	37.00	27.69
Realized gain on commodity derivatives (per Boe)	1.44	3.72	9.99
Total including derivative impact (per Boe)	$47.81	$40.72	$37.68
Production costs (per Boe)(1)	$ 4.57	$ 4.25	$ 4.20

(1) Production cost per Boe is made up of lease operating expenses, excluding ad valorem taxes. Production cost per Boe also excludes severance and production taxes.

Drilling Activity — Prior Three Years

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,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	69.0	64.2	91.0	56.2	28.0	16.0
Dry	2.0	2.0	—	—	4.0	2.0
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	69.0	64.2	91.0	56.2	28.0	16.0
Dry	2.0	2.0	—	—	4.0	2.0

Of the 71 gross (66.2 net) wells drilled in 2011, 18 gross (18 net) wells were waiting on completion at December 31, 2011. Of the two gross (two net) dry wells drilled in 2011, one was completed as a salt water disposal well and one was drilled as replacement well during the first three months of 2012.

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.

Drilling Activity — Current

As of the date of this report, we had three rigs running in the Permian Basin targeting the Wolffork and Canyon Sands formations, including two rigs drilling horizontal Wolfcamp wells.

Delivery Commitments

We are not committed to provide a fixed and determinable quantity of oil, NGLs or gas in the near future under existing agreements.

Producing Wells

The following table sets forth the number of producing wells in which we owned a working interest at December 31, 2011. Wells are classified as natural gas or oil according to their predominant production stream.

	Natural Gas Wells		Oil Wells		Total Wells		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Permian Basin	603.0	590.9	35.0	35.0	638.0	625.7	98.1%
East Texas Basin	9.0	4.5	—	—	9.0	4.5	50.0%
Total	612.0	595.4	35.0	35.0	647.0	630.2	97.4%

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2011.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	66,370	56,810	99,280	88,226	165,650	145,036
East Texas Basin	3,481	1,687	3,738	2,785	7,219	4,472
Total	69,851	58,497	103,018	91,011	172,869	149,508

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2011, that will expire over the next three years by project area unless production is established before lease expiration dates. Net amounts may be more than gross amounts in a particular year due to timing of expirations.

	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	5,641	8,705	18,636	15,943	41,523	32,438
East Texas Basin	3,423	2,506	315	279	—	—
Total	9,064	11,211	18,951	16,222	41,523	32,438

ITEM 3. *LEGAL PROCEEDINGS*

We are involved in various 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 business, financial condition or cash flows.

ITEM 4. *MINE SAFETY DISCLOSURES*

Not applicable.

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 2011, trading volume averaged 500,127 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.

	Price Per Share	
	High	**Low**
2011		
First quarter	$34.72	$22.58
Second quarter	34.93	19.13
Third quarter	28.37	15.55
Fourth quarter	33.48	14.14
2010		
First quarter	$ 9.65	$ 7.57
Second quarter	9.52	6.32
Third quarter	11.81	6.12
Fourth quarter	23.89	11.00

Holders

As of February 29, 2012, there were 100 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, 2011.

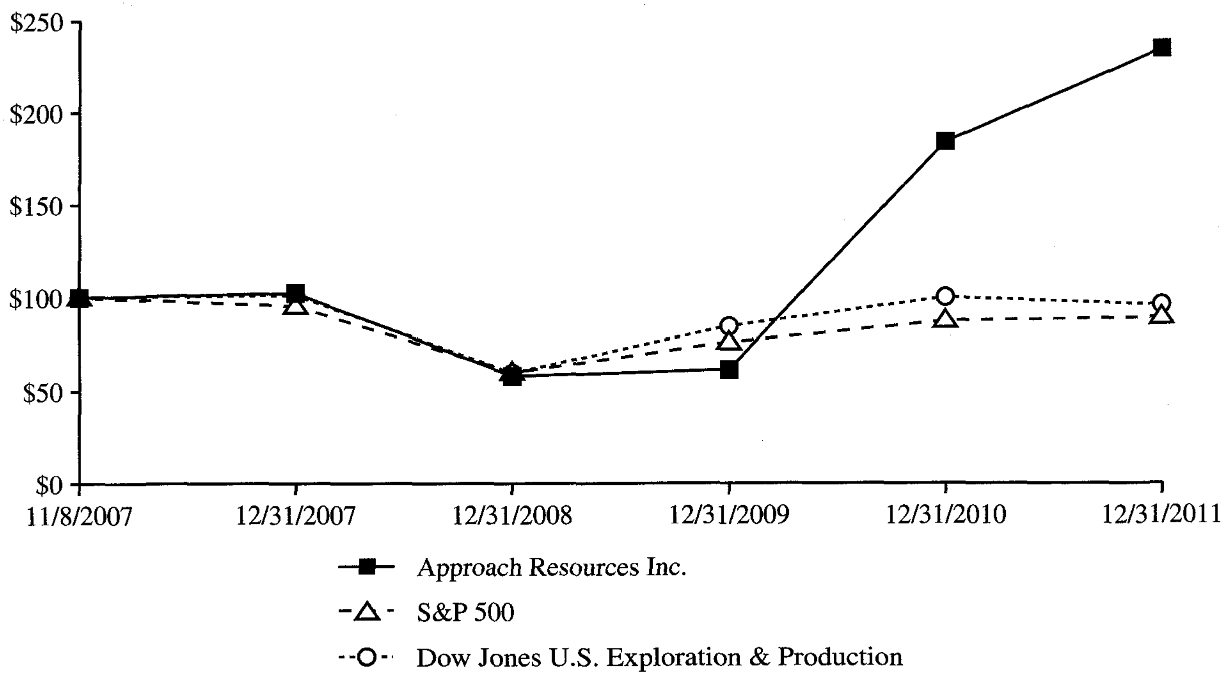
Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))(1) (c)
Equity compensation plans approved by stockholders	260,097	$5.13	1,225,376
Equity compensation plans not approved by stockholders	—	—	—

(1) Under our 2007 Stock Incentive Plan (the "2007 Plan"), and subject to adjustment for recapitalizations or reorganizations, the maximum number of shares of common stock that may be available for grant of awards under the 2007 Plan is 10% of the outstanding shares of our common stock, as adjusted on the first business day of each calendar year, plus shares of common stock that remain available for grant of awards under our prior plan. After adjustment for 10% of our outstanding shares of common stock on the first business day of 2012 as set forth in the 2007 Plan, we expect the number of shares remaining available for future issuance under the 2007 Plan under column (c) of above table to increase to 1,712,046.

Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from November 8, 2007, through December 31, 2011, to that of the cumulative return on a $100 investment in the Standard & Poor's 500 ("S&P 500") index and the Dow Jones U.S. Exploration & Production Total Stock Market 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. This graph is included in accordance with the SEC's disclosure rules. This historic stock performance is not indicative of future stock performance.

COMPARISON OF 49 MONTH CUMULATIVE TOTAL RETURN
Among Approach Resources Inc., the S&P 500 Index, and the Dow Jones U.S. Exploration & Production Total Stock Market Index



	11/8/2007	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
Approach Resources Inc.	$100.00	$102.14	$58.06	$61.32	$183.48	$ 233.60
S&P 500	100.00	95.15	59.95	75.81	87.23	89.07
D J U.S. Exploration & Production	100.00	101.09	59.62	84.37	99.89	95.80

Issuer Repurchases of Equity Securities

Our 2007 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 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 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 that May Yet Be Purchased Under the Plans or Programs
October 1, 2011 — October 31, 2011	—	—	—	—
November 1, 2011 — November 30, 2011	599	$28.65	—	—
December 1, 2011 — December 31, 2011	1,993	$32.88	—	—
Total	2,592	$31.90	—	—

ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth selected financial information for the five years ended December 31, 2011. All weighted average shares and per share data have been adjusted for the three-for-one stock split and the stock issuance resulting from our combination with Approach Oil & Gas Inc. under a contribution agreement in November 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,				
	2011	2010	2009	2008	2007
	(in thousands, except per-share data)				
Operating Results Data					
Revenues					
Oil, NGL and gas sales	$ 108,387	$ 57,581	$ 40,648	$ 79,869	$ 39,114
Expenses					
Lease operating	13,328	8,555	7,777	7,621	3,815
Severance and production taxes	5,806	2,990	1,996	4,202	1,659
Exploration	9,546	2,589	1,621	1,478	883
Impairment	18,476	2,622	2,964	6,379	267
General and administrative	17,900	11,422	10,617	8,881	12,667
Depletion, depreciation and amortization	32,475	22,224	24,660	23,710	13,098
Total expenses	97,531	50,402	49,635	52,271	32,389
Operating income (loss)	10,856	7,179	(8,987)	27,598	6,725
Other					
Impairment of investment	—	—	—	(917)	—
Interest expense, net	(3,402)	(2,189)	(1,787)	(1,269)	(5,219)
Realized gain on commodity derivatives	3,375	5,784	14,659	2,936	4,732
Unrealized (loss) gain on commodity derivatives	(347)	788	(9,899)	7,149	(3,637)
Gain on sale of oil and gas properties, net of foreign currency transaction loss	248	—	—	—	—
Income (loss) before provision (benefit) for income taxes	10,730	11,562	(6,014)	35,497	2,601
Provision (benefit) for income taxes	3,488	4,100	(785)	12,111	(108)
Net income (loss)	$ 7,242	$ 7,462	$ (5,229)	$ 23,386	$ 2,709
Earnings (loss) per share					
Basic	$ 0.25	$ 0.34	$ (0.25)	$ 1.13	$ 0.25
Diluted	$ 0.25	$ 0.34	$ (0.25)	$ 1.12	$ 0.24
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$ 95,770	$ 42,377	$ 39,761	$ 56,381	$ 30,746
Investing activities	(284,758)	(91,346)	(29,553)	(100,633)	(52,940)
Financing activities	165,843	69,748	(11,618)	43,750	22,062
Effect of Canadian exchange rate	(19)	1	18	(206)	6
Balance Sheet Data					
Cash and cash equivalents	$ 301	$ 23,465	$ 2,685	$ 4,077	$ 4,785
Other current assets	11,085	17,865	9,318	30,760	12,021
Property, equipment, net, successful efforts method	595,284	369,210	304,483	303,404	230,819
Other assets	1,224	2,549	2,440	—	1,101
Total assets	$ 607,894	$413,089	$318,926	$ 338,241	$248,726
Current liabilities	$ 43,625	$ 29,240	$ 21,996	$ 30,775	$ 22,017
Long-term debt	43,800	—	32,319	43,537	—
Other long-term liabilities	53,020	50,903	44,115	40,116	26,890
Stockholders' equity	467,449	332,946	220,496	223,813	199,819
Total liabilities and stockholders' equity	$ 607,894	$413,089	$318,926	$ 338,241	$248,726

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 1A. for additional discussion of some of these factors and risks.

Overview

Approach Resources Inc. is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on oil and gas reserves in oil shale and tight gas sands in the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger), where we lease approximately 145,000 net acres. Our management and technical team have a proven track record of finding and developing reserves through advanced completion, fracturing and drilling techniques. As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At December 31, 2011, our estimated proved reserves were 77.0 MMBoe. At such date, approximately 99.7% of our proved reserves were located in the Permian Basin in Crockett and Schleicher Counties, Texas. Important characteristics of our proved reserves at December 31, 2011, include:

- 61% oil and NGLs and 39% natural gas;
- 44% proved developed;
- 100% operated;
- Reserve life of over 33 years based on 2011 production of 2.3 MMBoe;
- Standardized Measure of $414.4 million; and
- PV-10 of $679.1 million.

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 for future income taxes. Estimated future net revenues are discounted at an annual rate of 10% to determine their present value. PV-10 is a non-GAAP, financial measure and generally differs from the Standardized Measure, 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 as computed under GAAP. See Item 2. "Properties — Proved Oil and Gas Reserves" for a reconciliation of PV-10 to the Standardized Measure.

At December 31, 2011, we owned working interests in 638 producing oil and gas wells in the Permian Basin, and we had an estimated 3,000 potential drilling locations, of which 395 were proved. We also had an estimated 190 potential Wolffork recompletion opportunities in the Permian Basin, of which four were proved. We also owned working interests in nine producing gas wells in the East Texas Basin.

2011 Activity

Our operations are focused on the Permian Basin, where our leasehold position is characterized by multiple oil and liquids-rich formations. Historically, we have focused our drilling on tight gas sands (Canyon Sands) and the Strawn and Ellenburger formations in the Permian Basin. Data from drilling vertical Canyon, Strawn and Ellenburger wells, combined with a detailed geological and petrophysical study, led to our decision to begin to develop the shallower Clearfork and Wolfcamp formations in late 2010. We sometimes refer to the Clearfork and Wolfcamp zones together as the "Wolffork" oil shale resource play, and our drilling program in the Permian Basin as "Project Pangea" and "Pangea West."

Proved Reserves and Production Growth

In 2011, our estimated proved reserves increased 52%, or 26.3 MMBoe, to 77.0 MMBoe from 50.7 MMBoe. Reserve growth in 2011 was driven by results in our Wolffork oil shale resource play as well as the Working Interest Acquisition.

Production for 2011 totaled 2.3 MMBoe (6.4 MBoe/d), compared to 1.6 MMBoe (4.3 MBoe/d) in 2010, a 50% increase. Production for 2011 was 21% oil, 34% NGLs and 45% natural gas. After the expiration of our prior gas sales contract in April 2011, we began realizing NGL revenues from the liquids-rich gas stream in southeast Project Pangea, and our NGL production increased 206% in 2011, compared to 2010. In addition, our continued development of Project Pangea increased oil production 96% in 2011, compared to 2010. On average, we operated two vertical rigs and one horizontal rig in 2011, and drilled a total of 71 gross (66.2 net) wells, of which 18 gross (18 net) were waiting on completion at December 31, 2011. We also recompleted 10 gross (10 net) wells in the Wolffork in 2011.

Liquids-Weighted Reserve Profile

Our proved reserve profile at year end 2011 was 61% oil and NGLs and 39% natural gas, compared to 51% oil and NGLs and 49% natural gas at year end 2010. During 2011, our proved oil and NGL reserves increased 21.6 MMBbls, or 84%, to 47.2 MMBbls from 25.6 MMBbls in 2010. Our increase in proved oil and NGL reserves is primarily due to the liquids-rich production and reserve profile of the Wolffork oil shale resource play and processing upgrades in southeast Project Pangea. On April 1, 2011, we began realizing NGL revenues from the liquids-rich gas stream in southeast Project Pangea.

Working Interest Acquisition

In February 2011, we closed the Working Interest Acquisition in northwest Project Pangea from two non-operating partners for $70.8 million, after customary post-closing adjustments. The Working Interest Acquisition was funded with cash on hand and borrowings under our revolving credit facility. As a result of the Working Interest Acquisition, our working and net revenue interests in Project Pangea are approximately 100% and 76%, respectively.

Acquisition of Acreage

We acquired approximately 43,000 net acres in the Permian Basin in Crockett and Schleicher Counties, Texas, during 2011. The acreage acquisitions increased our exposure to the Wolffork oil shale resource play.

2011 Equity Offering

In November 2011, we completed the 2011 Offering and sold 4.6 million shares of common stock at $28 per share. After deducting underwriting discounts and transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We intend to use the proceeds to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used the proceeds of the 2011 Offering to repay outstanding borrowings under our revolving credit facility.

Plans for 2012

In November 2011, we announced a drilling program that included two rigs to drill vertical wells targeting the Wolffork and Canyon Sands and one rig to drill horizontal wells targeting the Wolfcamp. Due to continued strong results from our horizontal Wolfcamp drilling program, we replaced one of our vertical drilling rigs with a second horizontal rig in Project Pangea in March 2012. In connection with the expansion of our horizontal Wolfcamp drilling program, our Board of Directors approved a $30 million increase in our 2012 capital budget to $190 million. We also expect to recomplete two to four wells per month in the Wolffork in 2012. Our objectives for 2012 include advancing our understanding of optimal well spacing, testing multi-zone potential and refining completion techniques to enhance hydrocarbon recovery in our Wolffork targets and improving our cost structure.

Our 2012 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, NGLs and gas, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

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 GAAP. 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.

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. We use the successful efforts method of accounting for our oil and gas activities.

Successful Efforts Method of Accounting

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 development 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.

Proved Reserves

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting* (the "Final Rule"), approving revisions designed to modernize oil and gas reserve reporting requirements. The Final Rule became 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 included:

- *Commodity prices.* Economic producibility of reserves 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, 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 Final Rule permits 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.
- *Third party reports.* We are required to file the report of any third party used to prepare or audit reserves our estimates.

In addition, in January 2010, the Financial Accounting Standards Board issued Accounting Standards Update, or the Update, 2010-03, "Oil and Gas Reserve Estimation and Disclosures" (the "Update") 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.

For the year ended December 31, 2011, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of 100% of our reported proved reserves, in accordance with guidelines established by the SEC, including the Final Rule.

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, 2011, were estimated based on the average of the closing price on the first day of each month for the 12-month period prior to December 31, 2011, for oil, NGLs and gas in accordance with the Final Rule. Changes in commodity prices and operations costs may increase or decrease estimates of proved oil, NGL and natural gas reserves. Depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGL and gas reserves. A hypothetical 10% decline in our December 31, 2011, estimated proved reserves would have increased our depletion expense by approximately $1.1 million for the year ended December 31, 2011.

See also Item 2. "Properties — Proved Oil and Gas Reserves" and Note 10 to our consolidated financial statements in this report 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 option 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 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 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 gain (loss) 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, 2011 and 2009, we recognized an unrealized loss of $347,000 and $9.9 million, respectively, from the change in the fair value of commodity derivatives. For the year ended December 31, 2010, we recognized an unrealized gain of $788,000 from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $1.4 million decrease in the December 31, 2011, 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.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil, NGLs and gas, future costs to produce these products, estimates of future oil and gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in commodity prices or downward revisions to estimated quantities of oil and gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

For 2011, we recorded an impairment expense of $18.5 million, of which $15.2 million was attributable to our oil and gas properties in the East Texas Basin. At December 31, 2011, we had $2.7 million recorded for the East Texas Basin, which is the estimated fair value at December 31, 2011. We also recorded an impairment expense of $3.3 million, related to all of our remaining carrying costs associated with our unproved properties in Northern New Mexico, which was the total carrying value we had recorded for the project.

Provision for Income Taxes

We estimate our provision for income taxes using historical tax basis information from prior years' income tax returns, along with the estimated changes to such bases from current period activity and enacted tax rates. Additionally, we compare liabilities to actual settlements of such assets or liabilities during the current period to identify considerations that might affect the current period's estimate.

Valuation of Share-Based Compensation

Our 2007 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.

In accordance with GAAP, we calculate the fair value of share-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We use (i) the Black-Scholes option price model to measure the fair value of stock options, (ii) the closing stock price on the date of grant for the fair value of restricted stock awards, including performance-based awards, and (iii) the Monte Carlo simulation method for the fair value of market-based awards.

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, 2011, 2010 or 2009. 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 and equipment. It may also increase the cost of labor or supplies.

Results of Operations

The following table sets forth summary information regarding oil, NGL and gas revenues, production, average product prices and average production costs and expenses for the last three years. We determined the Boe using the ratio of six Mcf of natural gas to one Boe, and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas or NGLs may differ significantly from the price for a barrel of oil.

	Years Ended December 31,		
	2011	2010	2009
Revenues (in thousands)			
Oil	$ 42,463	$18,640	$11,323
NGLs	41,029	10,765	5,919
Gas	24,895	28,176	23,406
Total oil, NGL and gas sales	108,387	57,581	40,648
Realized gain on commodity derivatives	3,375	5,784	14,659
Total oil, NGL and gas sales including derivative impact	$111,762	$63,365	$55,307
Production			
Oil (MBbls)	482	246	206
NGLs (MBbls)	798	261	209
Gas (MMcf)	6,345	6,290	6,320
Total (MBoe)	2,338	1,556	1,468
Total (MBoe/d)	6.4	4.3	4.0
Average prices			
Oil (per Bbl)	$ 88.18	$ 75.67	$ 54.97
NGLs (per Bbl)	51.39	41.19	28.32
Gas (per Mcf)	3.92	4.48	3.70
Total (per Boe)	$ 46.37	$ 37.00	$ 27.69
Realized gain on commodity derivatives (per Boe)	1.44	3.72	9.99
Total including derivative impact (per Boe)	$ 47.81	$ 40.72	$ 37.68
Costs and expenses (per Boe)			
Lease operating(1)	$ 5.70	$ 5.50	$ 5.30
Severance and production taxes	2.48	1.92	1.36
Exploration	4.08	1.66	1.10
Impairment	7.90	1.68	2.02
General and administrative	7.66	7.34	7.23
Depletion, depreciation and amortization	13.89	14.28	16.80

(1) Lease operating expenses per Boe include ad valorem taxes.

Oil, NGL and gas sales. Oil, NGL and gas sales increased $50.8 million, or 88%, to $108.4 million from $57.6 million in 2010. Of the $50.8 million increase in oil, NGL and gas sales, approximately $48.6 million was attributable to an increase in production volumes and $2.2 million was attributable to an increase in prices. Our 2011 oil, NGL and gas sales increased over 2010 due to increased production volumes from our drilling program in the Permian Basin, the Working Interest Acquisition and realization of NGL revenues in southeast Project Pangea resulting from a gas purchase and processing contract that provides for the sale of NGLs from the gas stream in the southeast portion of Project Pangea. In 2011, the average price we received for our production, before the effect of commodity derivatives, increased to $46.37 per Boe from $37.00 per Boe, or a 25% increase. Subject to commodity prices, we expect oil, NGL and gas sales to increase in 2012 due to increased production volumes from our drilling program in the Permian Basin.

Oil, NGL and gas sales increased $16.9 million, or 42%, in 2010 to $57.6 million from $40.6 million in 2009. Of the $16.9 million increase in oil, NGL and gas sales in 2010, approximately $11.9 million was attributable to an increase in prices we received for our natural gas, oil and NGL production, and approximately $5 million was attributable to an increase in production volumes. In 2010, the average price we received for our production, before the effect of commodity derivatives, increased to $37.00 per Boe from $27.69 per Boe, or a 34% increase.

The following table summarizes our oil, NGL and gas sales for each of the last three years (in thousands).

	Years Ended December 31,		
Revenues	**2011**	**2010**	**2009**
Oil	$ 42,463	$18,640	$11,323
NGLs	41,029	10,765	5,919
Gas	24,895	28,176	23,406
Total oil, NGL and gas sales	108,387	57,581	40,648
Realized gain on commodity derivatives	3,375	5,784	14,659
Total oil, NGL and gas sales including derivative impact	$111,762	$63,365	$55,307

The following table summarizes the prices we received for oil, NGLs and gas for each of the last three years.

	Years Ended December 31,		
Average prices	**2011**	**2010**	**2009**
Oil (per Bbl)	$88.18	$75.67	$54.97
NGLs (per Bbl)	51.39	41.19	28.32
Gas (per Mcf)	3.92	4.48	3.70
Total (per Boe)	$46.37	$37.00	$27.69
Realized gain on commodity derivatives (per Boe)	1.44	3.72	9.99
Total including derivative impact (per Boe)	$47.81	$40.72	$37.68

Net income (loss). Net income for 2011 was $7.2 million, or $0.25 per diluted share, compared to net income of $7.5 million, or $0.34 per diluted share for 2010 and a net loss of $5.2 million, or $0.25 per diluted share, for 2009. Net income per diluted share decreased in 2011 over 2010 primarily due to higher total expenses, including higher impairment and depletion, depreciation and amortization expenses. Net income per diluted share increased in 2010 from 2009 primarily due to higher revenues and higher realized prices.

Oil, NGL and gas production. Production for 2011 totaled 2,338 MBoe (6.4 MBoe/d), compared to 1,556 MBoe (4.3 MBoe/d) produced in 2010, an increase of 50%. Production for 2011 was 21% oil, 34% NGLs and 45% natural gas, compared to 16% oil, 17% NGLs and 67% natural gas in 2010. The increase in production in

2011 is the result of our continued development of our Permian Basin properties, the Working Interest Acquisition and processing NGLs in the southeast portion of Project Pangea; however, production was impacted during the second half of 2011 by oil takeaway constraints due to increased industry activity in the Permian Basin and a shortage of oil trucking capacity. We expect 2012 production to continue to increase over 2011 due to our expected drilling program in the Permian Basin.

Production for 2010 totaled 1,556 MBoe (4.3 MBoe/d), compared to 1,468 MBoe (4 MBoe/d) in 2009, a 6% increase. Oil and NGL production for 2010 increased 22% to 507 MBbls, compared to 415 MBbls produced in 2009. Production for 2010 was 16% oil, 17% NGLs and 67% natural gas, compared to 14% oil, 14% NGLs and 72% natural gas in 2009. Production volumes for 2010 increased as a result of our ongoing development activities in the Permian Basin, partially offset by the natural decline of our production.

The following table summarizes our production for each of the last three years.

	Years Ended December 31,		
Production	**2011**	**2010**	**2009**
Oil (MBbls)	482	246	206
NGLs (MBbls)	798	261	209
Gas (MMcf)	6,345	6,290	6,320
Total (MBoe)	2,338	1,556	1,468
Total (MBoe/d)	6.4	4.3	4.0

Commodity derivative activities. Realized gains from our commodity derivative activity increased our earnings by $3.4 million, $5.8 million and $14.7 million for 2011, 2010 and 2009, respectively. Realized gains and losses are derived from the relative movement of commodity prices in relation to the fixed notional pricing of our commodity derivatives positions or the range of prices in our collars for the respective years. The unrealized loss on commodity derivatives was $347,000 and $9.9 million for 2011 and 2009, respectively, and the unrealized gain on commodity derivatives was $788,000 for 2010. As commodity prices increase or decrease, the fair value of the open portion of those positions decreases or 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 ("LOE") increased $4.7 million, or 55%, for 2011, to $13.3 million ($5.70 per Boe) from $8.6 million ($5.50 per Boe) for 2010. The increase in LOE for 2011 was primarily attributable to the Working Interest Acquisition. In February 2011, we acquired the remaining 38% working interest in northwest Project Pangea, which increased our working interest to approximately 100%. The increase in LOE per Boe was primarily due to an increase in well repair and maintenance, partially offset by a decrease in ad valorem taxes, compressor rental and repair and water hauling, insurance and other LOE over the prior year. For 2012, we expect LOE per Boe to be relatively consistent with 2011 despite higher service costs, which we expect will be partially offset by increased production volumes.

Our LOE for 2010 was $8.6 million ($5.50 per Boe), compared to $7.8 million ($5.30 per Boe) for 2009. The increase in LOE per Boe over the prior year period was primarily due to an increase in water hauling and insurance and ad valorem taxes, partially offset by a decrease in compressor rental and repair over the prior year period. Compressor related expenses declined due to the release of a rental amine plant during the second half of 2009 and lower negotiated compressor rentals. Ad valorem taxes and water hauling, insurance and other LOE increased as a result of an increase in the number of wells from our continued development in the Permian Basin.

The following table summarizes LOE per Boe.

	Year Ended December 31,				Year Ended December 31,			
	2011	2010	Change	%Change	2010	2009	Change	%Change
Compressor rental and repair	$1.36	$1.45	$(0.09)	(6.2)%	$1.45	$1.62	$(0.17)	(10.5)%
Ad valorem taxes	1.13	1.24	(0.11)	(8.9)	1.24	1.20	0.04	3.3
Water hauling, insurance and other	1.08	1.16	(0.08)	(6.9)	1.16	0.86	0.30	34.9
Pumpers and supervision	1.05	1.01	0.04	4.0	1.01	1.00	0.01	1.0
Well repair and maintenance	1.00	0.54	0.46	85.2	0.54	0.56	(0.02)	(3.6)
Workovers	0.08	0.10	(0.02)	(20.0)	0.10	0.06	0.04	66.7
Total	$5.70	$5.50	$ 0.20	3.6%	$5.50	$5.30	$ 0.20	3.8%

Severance and production taxes. Our severance and production taxes increased $2.8 million, or 93%, for 2011 to $5.8 million from $3 million for 2010. The increase in severance and production taxes was primarily the result of an increase in oil, NGL and gas sales over 2010. Severance and production taxes were approximately 5.4% and 5.2% of oil, NGL and gas sales for the respective periods. For 2012, we expect severance and production taxes as a percent of oil, NGL and gas sales will remain relatively consistent compared to the severance and production taxes for 2011.

Our severance and production taxes increased $1 million, or 50%, for 2010 to $3 million from $2 million for 2009. The increase in severance and production taxes was primarily due to the increase in oil, NGL and gas sales between 2010 and 2009. Severance and production taxes amounted to approximately 5.2% and 4.9% of oil, NGL and gas sales for the respective periods.

Exploration expense. We recorded $9.5 million of exploration expense for 2011. Exploration expense for 2011 resulted primarily from lease extensions and expirations in the Permian Basin and the acquisition of 3-D seismic data in Pangea West. During 2011, we extended the acreage terms for an additional four years for approximately 9,200 acres in the northwest area of Project Pangea for $3.2 million, or approximately $350 per acre. Further, approximately 5,000 acres in the southeast area of Project Pangea expired during 2011 resulting in approximately $1.2 million of exploration expense. For 2012, we expect exploration expense to be less than 2011 due to fewer lease extensions and expirations.

We recorded $2.6 million and $1.6 million of exploration expense for 2010 and 2009, respectively. Exploration expense for 2010 resulted primarily from 3-D seismic acquisition in northwest Project Pangea and lease renewals in Project Pangea and Kentucky. Exploration expense for the 2009 period resulted primarily from the expiration of leases for approximately 2,300 net acres Project Pangea and East Texas.

Impairment. We review our long-lived assets, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting. For 2011, our total impairment expense was $18.5 million. Due to ongoing, low natural gas prices and to the further decline in natural gas prices during the three months ended December 31, 2011, we recorded an impairment expense to our oil and gas properties in the East Texas Basin of $15.2 million in 2011. At December 31, 2011, we had $2.7 million recorded for our properties in the East Texas Basin, which is the estimated fair value at December 31, 2011. We also recorded an impairment expense of $3.3 million, which was all of our remaining carrying costs associated with our unproved properties in Northern New Mexico.

We recorded an impairment of unproved oil and gas properties of $2.6 million and $3 million in 2010 and 2009, respectively. The 2010 impairment resulted from a write-off of $2.6 million in costs in our Southwest Kentucky project, and represented the remaining carrying value we had recorded for the project. The 2009 impairment resulted from a write-off of $3 million in costs in Northeast British Columbia, and represented the remaining carrying value we had recorded for the project.

General and administrative expenses. Our general and administrative expenses ("G&A") increased $6.5 million, or 57%, to $17.9 million ($7.66 per Boe) for 2011 from $11.4 million ($7.34 per Boe) for 2010. The increase in G&A was primarily due to higher salaries and benefits, and share-based compensation. For 2012, we expect G&A to be higher, compared to 2011, as a result of higher share-based compensation and staffing increases. However, we expect G&A to be lower on a per Boe basis.

Our G&A increased $805,000, or 8%, to $11.4 million ($7.34 per Boe) for 2010, from $10.6 million ($7.23 per Boe) for 2009. The increase in G&A was principally due to higher share-based compensation, salaries and benefits.

The following table summarizes G&A (in millions).

	Year Ended December 31,				Year Ended December 31,			
	2011	**2010**	**Change**	**% Change**	**2010**	**2009**	**Change**	**% Change**
Salaries and benefits	$ 8.1	$ 5.3	$2.8	52.8%	$ 5.3	$ 5.0	$ 0.3	6.0%
Share-based compensation	4.7	2.6	2.1	80.8	2.6	1.8	0.8	44.4
Professional fees	1.4	1.3	0.1	7.7	1.3	1.4	(0.1)	(7.1)
Other	3.7	2.2	1.5	68.2	2.2	2.4	(0.2)	(8.3)
Total	$17.9	$11.4	$6.5	57.0%	$11.4	$10.6	$ 0.8	7.5%

Depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expense ("DD&A") increased $10.3 million, or 46%, to $32.5 million for 2011, from $22.2 million for 2010. Our DD&A per Boe decreased by $0.39, or 3%, to $13.89 per Boe for 2011, compared to $14.28 per Boe for 2010. The increase in DD&A was primarily attributable to higher capitalized costs over 2010, partially offset by an increase in estimated proved developed reserves.

DD&A decreased $2.4 million, or 9.9%, to $22.2 million for 2010, from $24.7 million for 2009. Our DD&A per Boe decreased by $2.52, or 15%, to $14.28 per Boe for 2010, compared to $16.80 per Boe for 2009. The decrease in DD&A was primarily attributable to an increase in estimated proved developed reserves at December 31, 2010, partially offset by higher capital costs over the prior year.

Interest expense, net. Our interest expense, net, increased $1.2 million, or 55%, to $3.4 million for 2011, from $2.2 million for 2010. This increase was the result of higher average notes payable balances outstanding. The weighted average interest rate applicable to our outstanding borrowings during 2011 and 2010, was 3.1% and 3.4%, respectively.

Our interest expense increased $402,000, or 22.5%, to $2.2 million for 2010, from $1.8 million for 2009. This increase was the result of higher average notes payable balances outstanding as well as an increase in amortization of $268,000 for deferred loan costs during 2010. The weighted average interest rate applicable to our outstanding borrowings during 2010 and 2009, was 3.4% and 3.2%, respectively.

Income taxes. Our income taxes decreased $612,000 to $3.5 million for 2011, from $4.1 million for 2010. The decrease in income taxes was due to lower pre-tax income in 2011 and a lower effective income tax rate. Our effective income tax rate for 2011 and 2010 was 32.5% and 35.5%, respectively. The lower income tax rate in 2011 was a result of an increased impact in permanent differences.

Our income taxes increased $4.9 million to $4.1 million for 2010, from a benefit of $785,000 for 2009. The increase in income taxes was due to higher pre-tax income in 2010, partially offset by higher taxes in 2009 from a change in our estimated income tax provision for the year ended December 31, 2008. Our effective income tax rate for 2010 was 35.5%, compared with 13.1% for 2009. The lower effective tax rate in the 2009 period primarily resulted from an increased impact of permanent differences from book and taxable income, partially offset by an increase in our estimated income taxes for the year ended December 31, 2008.

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, 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. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

Liquidity

We define liquidity as funds available under our revolving credit facility plus year-end net cash and cash equivalents. We had $43.8 million and $32.3 million in long-term debt outstanding under our revolving credit facility at December 31, 2011, and 2009, respectively. We had no long-term debt outstanding under our revolving credit facility at December 31, 2010.

The following table summarizes our liquidity position at December 31, 2011, 2010 and 2009 (in thousands).

	Year Ended December 31,		
	2011	2010	2009
Borrowing base	$260,000	$150,000	$115,000
Cash and cash equivalents	301	23,465	2,685
Long-term debt	(43,800)	—	(32,319)
Undrawn letters of credit	(350)	(350)	(400)
Liquidity	$216,151	$173,115	$ 84,966

In February 2011, we acquired an additional 38% working interest in Cinco Terry from two non-operating partners for $70.8 million, after post-closing adjustments. The Working Interest Acquisition was funded with borrowings under our revolving credit facility and cash on hand.

In November 2011, we completed an equity offering and issued an aggregate of 4.6 million shares of our common stock at $28 per share in an underwritten public offering (the "2011 Offering"). After deducting underwriting discounts and transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million, which we intend to use to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used the proceeds of the 2011 Offering to repay outstanding borrowings under our revolving credit facility.

In November 2010, we issued 6.6 million shares of common stock at $16.25 per share. After deducting underwriting discounts and estimated transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million. We used the proceeds of the offering to repay all outstanding borrowings under our revolving credit facility, fund development of our Wolffork oil shale resource play and general working capital needs.

In 2009, while commodity prices were low and demand for natural gas was reduced, we decreased our capital spending to preserve liquidity and improve our financial position. As a result, we paid down long-term debt and increased liquidity by over 40%, from $60.5 million at December 31, 2008, to $85.4 million at December 31, 2009.

Working Capital

Our working capital is affected primarily by our cash and cash equivalents balance and our capital spending program. At December 31, 2011, we had a working capital deficit of $32.2 million, compared to a working capital surplus of $12.1 million and a working capital deficit of $10 million at December 31, 2010 and 2009, respectively. The change in working capital for 2011 is primarily attributable to capital expended on our drilling program. Our working capital deficits have been historically attributable to accrued liabilities and have been more than offset by liquidity available under our revolving credit facility. To the extent we operate or end the year 2012 with a working capital deficit, we expect such deficit to be more than offset by liquidity available under our revolving credit facility.

Cash Flows

The following table summarizes our sources and uses of funds for the periods noted (in thousands).

	Year Ended December 31,		
	2011	2010	2009
Cash flows provided by operating activities	$ 95,770	$ 42,377	$ 39,761
Cash flows used in investing activities	(284,758)	(91,346)	(29,553)
Cash flows provided by (used in) financing activities	165,843	69,748	(11,618)
Effect of Canadian exchange rate	(19)	1	18
Net decrease in cash and cash equivalents	$ (23,164)	$ 20,780	$ (1,392)

For 2011, our primary sources of cash were from operating activities and financing activities. Approximately $95.8 million of cash from operations and $165.8 million of cash from financing activities were used to fund a portion of our drilling program and the Working Interest Acquisition. In November 2011, we sold 4.6 million shares of common stock. After deducting underwriting discounts and estimated transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We used the proceeds of the offering to repay outstanding borrowings under our revolving credit facility.

For 2010, our primary sources of cash were from operating activities and financing activities. Approximately $42.4 million of cash from operations was used to fund a portion of our drilling program and pay down our long-term debt. In November 2010, we sold 6.6 million shares of common stock. After deducting underwriting discounts and estimated transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million. We used a portion of the proceeds of the offering to repay all outstanding borrowings under our revolving credit facility.

In 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.

Operating Activities

For 2011, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling activities and leasehold acquisitions in the Permian Basin and the Working Interest Acquisition. Cash flows from operating activities increased by $53.4 million, or 126%, to $95.8 million from $42.4 million in 2010, primarily due to an 88% increase in oil, NGL and gas sales in 2011.

For 2010, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling activities in Project Pangea, leasehold acquisitions and a 3-D seismic program in our Permian Basin operations. Cash flows from operating activities increased by 6.8%, or $2.7 million, to $42.4 million from 2009 partially due to a 42% increase in oil and gas sales in 2010. Cash flows provided by operating activities also were affected by an increase in cash flows used by working capital during 2010.

For 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.

Investing Activities

Cash flows used in investing activities increased by $193.4 million, or 212% for 2011, compared to 2010, which primarily reflects the Working Interest Acquisition for $70.8 million, net of purchase price adjustments, and expenditures for drilling and lease acquisitions and extensions in our core operating area in the Permian Basin.

Cash flows used in investing activities increased by $61.8 million for 2010 as compared to 2009, which primarily reflects expenditures for drilling and acquisitions in our core operating area in the Permian Basin. During 2010, we drilled a total of 91 gross (56.2 net) wells, compared to 32 gross (18 net) wells in 2009. Also in 2010, we acquired a 10% working interest in northwest Project Pangea from a non-operating partner for $21.2 million, net of purchase price adjustments.

The majority of our cash flows used in investing activities for the years ended 2011, 2010 and 2009 have been used for drilling and acquisitions in our core operating area in the Permian Basin and East Texas Basin.

The following table is a summary of capital expenditures related to our oil and gas properties (in thousands).

	Years Ended December 31,		
	2011	2010	2009
Permian Basin	$179,395	$56,211	$26,398
Permian Basin acquisitions	70,827	21,179	—
Subtotal	250,022	77,390	26,398
East Texas Basin	560	101	1,554
Exploratory projects	445	285	237
Inventory and other	1,377	1,636	(1,959)
Lease acquisition, geological and geophysical	31,970	11,604	2,760
Total	$284,574	$91,016	$28,990

Financing Activities

We borrowed $246.8 million under our revolving credit facility in 2011, compared to $121.8 million in 2010 and $67.4 million in 2009. We repaid a total of $203 million, $154.1 million and $78.6 million of amounts outstanding under our revolving credit facility for 2011, 2010 and 2009, respectively.

In November 2011, we completed the 2011 Offering and sold 4.6 million shares of common stock at $28 per share. After deducting underwriting discounts and transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We intend to use the proceeds to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used the proceeds of the 2011 Offering to repay outstanding borrowings under our revolving credit facility.

In November 2010, we sold 6.6 million shares of common stock in an underwritten public offering. After deducting underwriting discounts and estimated transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million. We used the proceeds of the offering to repay all outstanding borrowings under our revolving credit facility, fund development of our Wolffork oil shale resource play and general working capital needs.

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.

2012 Capital Expenditures

In November 2011, we announced a drilling program that included two rigs to drill vertical wells targeting the Wolffork or Canyon Sands and one rig to drill horizontal wells targeting the Wolfcamp. Due to continued, strong results from our horizontal Wolfcamp drilling program, we replaced one of our vertical drilling rigs with a second horizontal rig in Project Pangea in March 2012. In connection with the expansion of our horizontal Wolfcamp drilling program, our Board of Directors approved a $30 million increase in our 2012 capital budget to $190 million. We also expect to recomplete two to four wells per month in the Wolffork in 2012. Our objectives for 2012 include advancing our understanding of optimal well spacing, multi-zone potential and hydrocarbon recovery and improving our cost structure.

Our 2012 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, gas and NGLs, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Revolving Credit Facility

We have a $300 million revolving credit facility with a borrowing base set at $260 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.

The maturity date under our revolving credit facility is July 31, 2014. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

We had outstanding borrowings of $43.8 million under our revolving credit facility at December 31, 2011. We had no outstanding borrowings at December 31, 2010. The interest rate applicable to our revolving credit facility at December 31, 2011, was 3.7%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at December 31, 2011, 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.

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 4.0 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 noncash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or nonrecurring 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 defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At December 31, 2011, 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 Obligations

As of December 31, 2011, our contractual obligations include long-term debt, daywork drilling contracts, service contracts, operating lease obligations, asset retirement obligations and employment agreements with our executive officers.

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 daywork drilling contracts was $3.4 million at December 31, 2011.

In December 2011, we extended an 18-month contract for a dedicated, third-party fracture stimulation fleet by three months. The contract requires a minimum commitment of $16.5 million per quarter for the contract term. The contract contains early termination provisions for a monthly fee of less than the minimum quarterly commitment in the event of a termination before the end of the contract term.

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 December 2010, we expanded our office space under an amendment to the lease to approximately 23,400 square feet. In January 2011, we began additional rent payments of approximately $9,000 per month, bringing our total office lease payment to approximately $45,000 per month.

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.

At December 31, 2011, we had outstanding employment agreements with each of our five executive officers that contained automatic renewal provisions providing that such agreements may be automatically renewed for successive terms of one year unless the 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 each terminated without cause, was approximately $4 million at December 31, 2011.

The following table summarizes these commitments as of December 31, 2011 (in thousands).

	Payments Due By Period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt(1)	$43,800	$ —	$43,800	$—	$ —
Daywork drilling contracts(2)	3,382	3,382	—	—	—
Service contracts(3)	30,000	—	30,000	—	—
Operating lease obligations(4)	635	510	115	10	—
Asset retirement obligations(5)	6,730	—	—	—	6,730
Employment agreements with executive officers	3,963	3,963	—	—	—
Total	$88,510	$7,855	$73,915	$10	$6,730

(1) Borrowings under our credit agreement.

(2) At December 31, 2011, daywork drilling contracts related to three drilling rigs were contracted through January 31, 2012, March 1, 2012, and March 31, 2012, respectively.

(3) We are a party to a dedicated hydraulic fracturing services contract that requires minimum revenue payments of $5.5 million per month through the term of October 1, 2013. The contract contains early termination provisions for a monthly fee of less than the minimum monthly commitment in the event of a termination before the end of the contract term. If the service provider fails to provide certain minimal levels of service or otherwise breaches the agreement, no early termination fee is due. The table above assumes payment of required monthly fee during the applicable notice period and early termination fee through the end of the contract term.

(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, 2011, 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.

General Trends and Outlook

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 domestic and foreign supply of oil and gas, overall domestic and global economic conditions, commodity processing, gathering and transportation availability and the availability of refining capacity, price and availability of alternative fuels, price and quantity of foreign imports, domestic and foreign governmental regulations, political conditions in or affecting other gas producing and oil producing countries, weather and technological advances affecting oil and gas consumption. 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 and increase future expected costs necessary to develop existing reserves.

We also face the challenge of financing exploration, development and future acquisitions. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

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, 2011, were estimated based on the average of the closing price on the first day of each month for the 12-month period prior to December 31, 2011, for oil, NGLs and natural gas in accordance with SEC rules. Changes in commodity prices and operations costs may increase or decrease estimates of proved oil, NGL and natural gas reserves. Depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGL and natural gas reserves. A hypothetical 10% decline in our December 31, 2011, estimated proved reserves would have increased our depletion expense by approximately $1.1 million for the year ended December 31, 2011.

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 write down our oil and gas properties.

We enter into financial swaps and options 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.

The table below summarizes our commodity derivatives positions outstanding at December 31, 2011.

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Natural Gas – 2012	Call	230,000 MMBtu/month	$6.00/MMBtu
Crude Oil – 2012	Collar	700 Bbls/d	$85.00/Bbl – $97.50/Bbl
Crude Oil – 2012	Collar	500 Bbls/d	$90.00/Bbl – $106.10/Bbl

The table below summarizes commodity derivatives positions that we entered into after December 31, 2011.

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Natural Gasoline – February 2012 – December 2012	Swap	225 Bbls/d	$95.55/Bbl
Normal Butane – March 2012 – December 2012	Swap	225 Bbls/d	$73.92/Bbl
Crude Oil – 2013	Collar	650 Bbls/d	$90.00/Bbl – $105.80/Bbl
Crude Oil – 2014	Collar	550 Bbls/d	$90.00/Bbl – $105.50/Bbl

At December 31, 2011 and December 31, 2010, the fair value of our open derivative contracts was a net liability of approximately $1.4 million and $1.1 million, respectively.

JPMorgan Chase Bank, N.A. 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 the documentation agent and 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 option 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, 2011 and 2009, we recognized an unrealized loss of $347,000 and $9.9 million, respectively, from the change in the fair value of commodity derivatives. For the year ended December 31, 2010, we recognized an unrealized gain of $788,000 from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $1.4 million decrease in the December 31, 2011, 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, 2011, 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, 2011, 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, 2011, our Level 3 measurements were used to calculate our asset retirement obligation and our impairment analysis of proved properties at December 31, 2011. Additionally, Level 3 measurements were used to calculate our estimated fair value of our oil and gas properties in the East Texas Basin. We valued these properties by estimating future discounted net cash flows of reserves using forward market prices adjusted for locational basis differentials and other costs.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.*

Our consolidated financial statements and supplemental data are included in this report beginning on page F-1.

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

We had no changes in, and no disagreements with our accountants on, accounting and financial disclosure.

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, 2011. Based on this evaluation, our President and Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2011, 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, 2011. Hein & Associates LLP ("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, 2011, 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 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

Information required under Item 10 of this report will be contained under the captions "Election of Directors—Directors," "Executive Officers" and "Corporate Governance" to be provided in our proxy statement for our 2012 annual meeting of stockholders to be filed with the SEC on or before April 30, 2012, 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 Compensation and Nominating 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 definitive proxy statement for our 2012 annual meeting of stockholders to be filed with the SEC on or before April 30, 2012, 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 definitive proxy statement for our 2012 annual meeting of stockholders to be filed with the SEC on or before April 30, 2012, 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 — Board Independence" in our definitive proxy statement for our 2012 annual meeting of stockholders to be filed with the SEC on or before April 30, 2012, 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 2012 annual meeting of stockholders to be filed with the SEC on or before April 30, 2012, 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 70 for a description of the exhibits filed as part of this report.

GLOSSARY AND SELECTED ABBREVIATIONS

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 to reference oil, condensate or NGLs.

Boe. Barrel of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.

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, for 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, 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.

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

Dry hole or well. 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.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

Farm-in. An arrangement in which the owner or lessee of mineral rights (the first party) assigns a working interest to an operator (the second party), the consideration for which is specified exploration and/or development activities. The first party retains an overriding royalty, working interest or other type of economic interest in the mineral production. The arrangement from the viewpoint of the second party is termed a "farm-in" arrangement.

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.

Hydraulic fracturing. The technique designed to improve a well's production rates by pumping a mixture of water and sand (in our case, over 99% by mass) and chemical additives (in our case, less than 1% by mass) into the formation and rupturing the rock, creating an artificial channel.

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.

MBoe. Thousand barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.

Mcf. Thousand cubic feet of natural gas.

MMBoe. Million barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of gas.

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. The portions of gas from a reservoir that are liquefied at the surface in separators, field facilities or gas processing plants.

NYMEX. New York Mercantile Exchange.

Play. A set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Productive well. An 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:

(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.

Proved oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, 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. 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% 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.

"Recompletion" or to "recomplete" a well. The addition of production from another interval or formation in an existing wellbore.

Reserve life. This index is calculated by dividing year-end 2011 estimated proved reserves by 2011 production of 2,338 MBoe 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.

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 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:

> 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, 2012

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, 2012.

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 Accounting Officer)
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director and Chairman of the Board of Directors
/s/ Alan D. Bell Alan D. Bell	Director
/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, 2011. 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, 2011, 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, 2012

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, 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, changes in stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2011, and our report dated March 12, 2012, expressed an unqualified opinion.

/s/ ***HEIN** & ASSOCIATES LLP*

Dallas, Texas
March 12, 2012

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, 2011 and 2010, and the related consolidated statements of operations, changes in stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ ***HEIN*** & ASSOCIATES LLP

Dallas, Texas
March 12, 2012

Approach Resources Inc. and Subsidiaries

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

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 301	$ 23,465
Accounts receivable:		
Joint interest owners	179	8,319
Oil, NGL and gas sales	10,060	6,044
Unrealized gain on commodity derivatives	—	862
Prepaid expenses and other current assets	342	322
Deferred income taxes — current	504	2,318
Total current assets	11,386	41,330
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	732,659	474,917
Furniture, fixtures and equipment	1,621	1,077
	734,280	475,994
Less accumulated depletion, depreciation and amortization	(138,996)	(106,784)
Net properties and equipment	595,284	369,210
OTHER ASSETS	1,224	2,549
Total assets	$ 607,894	$ 413,089
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Advances from non-operators	$ —	$ 509
Accounts payable	12,599	11,426
Oil, NGL and gas sales payable	4,748	5,534
Accrued liabilities	24,837	10,686
Unrealized loss on commodity derivatives	1,441	1,085
Total current liabilities	43,625	29,240
NON-CURRENT LIABILITIES:		
Long-term debt	43,800	—
Unrealized loss on commodity derivatives	—	871
Deferred income taxes	46,290	44,616
Asset retirement obligations	6,730	5,416
Total liabilities	140,445	80,143
COMMITMENTS AND CONTINGENCIES (Note 8)		
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, 33,093,594 and 28,226,890 issued and outstanding, respectively	331	282
Additional paid-in capital	400,890	273,912
Retained earnings	66,228	58,986
Accumulated other comprehensive loss	—	(234)
Total stockholders' equity	467,449	332,946
Total liabilities and stockholders' equity	$ 607,894	$ 413,089

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, 2011	2010	2009
REVENUES:			
Oil, NGL and gas sales	$ 108,387	$ 57,581	$ 40,648
EXPENSES:			
Lease operating	13,328	8,555	7,777
Severance and production taxes	5,806	2,990	1,996
Exploration	9,546	2,589	1,621
Impairment	18,476	2,622	2,964
General and administrative	17,900	11,422	10,617
Depletion, depreciation and amortization	32,475	22,224	24,660
Total expenses	97,531	50,402	49,635
OPERATING INCOME (LOSS)	10,856	7,179	(8,987)
OTHER:			
Interest expense, net	(3,402)	(2,189)	(1,787)
Realized gain on commodity derivatives	3,375	5,784	14,659
Unrealized (loss) gain on commodity derivatives	(347)	788	(9,899)
Gain on sale of oil and gas properties, net of foreign currency transaction loss	248	—	—
INCOME (LOSS) BEFORE INCOME TAX PROVISION (BENEFIT)	10,730	11,562	(6,014)
INCOME TAX PROVISION (BENEFIT)	3,488	4,100	(785)
NET INCOME (LOSS)	$ 7,242	$ 7,462	$ (5,229)
EARNINGS (LOSS) PER SHARE:			
Basic	$ 0.25	$ 0.34	$ (0.25)
Diluted	$ 0.25	$ 0.34	$ (0.25)
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	28,930,792	22,065,797	20,869,832
Diluted	29,158,598	22,214,070	20,869,832

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Comprehensive Income
(In thousands)

	For the Years Ended December 31,		
	2011	2010	2009
Net income (loss)	$7,242	$7,462	$(5,229)
Other comprehensive income (loss):			
Foreign currency translation, net of related income tax	(20)	(4)	266
Reclassification of foreign currency transaction loss to earnings, net of related income tax	254	—	—
Total comprehensive income (loss)	$7,476	$7,458	$(4,963)

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, 2009, 2010 and 2011 (In thousands, except shares and per-share amounts)

	Common Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Income (Loss)	Total
BALANCES, January 1, 2009	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
Issuance of common stock upon exercise of options	58,798	1	750	—	—	751
Issuance of common stock, net of issuance costs	6,612,500	66	101,698	—	—	101,764
Issuance of common shares to directors for compensation	46,347	—	380	—	—	380
Restricted stock issuance, net of cancellations	560,870	6	(6)	—	—	—
Share-based compensation expense	—	—	2,248	—	—	2,248
Surrender of restricted shares for payment of income taxes	(10,910)	—	(89)	—	—	(89)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(62)	—	—	(62)
Net income	—	—	—	7,462	—	7,462
Foreign currency translation adjustments, net of related income tax of $2	—	—	—	—	(4)	(4)
BALANCES, December 31, 2010	28,226,890	282	273,912	58,986	(234)	$332,946
Issuance of common stock upon exercise of options	74,241	1	1,008	—	—	1,009
Issuance of common stock, net of issuance costs	4,600,000	46	122,104	—	—	122,150
Issuance of common shares to directors for compensation	18,446	—	420	—	—	420
Restricted stock issuance, net of cancellations	205,475	2	(2)	—	—	—
Share-based compensation expense	—	—	4,263	—	—	4,263
Surrender of restricted shares for payment of income taxes	(31,458)	—	(815)	—	—	(815)
Net income	—	—	—	7,242	—	7,242
Foreign currency transaction and translation adjustments, net of related income tax of $85	—	—	—	—	234	234
BALANCES, December 31, 2011	33,093,594	$331	$400,890	$66,228	$ —	$467,449

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,		
	2011	2010	2009
OPERATING ACTIVITIES:			
Net income (loss)	$ 7,242	$ 7,462	$ (5,229)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	32,475	22,224	24,660
Unrealized loss (gain) on commodity derivatives	347	(788)	9,899
Impairment	18,476	2,622	2,964
Gain on sale of oil and gas properties, net of foreign currency transaction loss	(248)	—	—
Exploration expense	9,546	2,589	1,621
Share-based compensation expense	4,683	2,628	1,826
Deferred income taxes	3,488	4,100	(785)
Changes in operating assets and liabilities:			
Accounts receivable	6,168	(6,581)	12,352
Prepaid expenses and other current assets	378	527	71
Accounts payable	(151)	6,083	(7,863)
Oil, NGL and gas sales payable	(786)	1,760	(857)
Accrued liabilities	14,152	(249)	1,102
Cash provided by operating activities	95,770	42,377	39,761
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(284,574)	(91,016)	(28,990)
Proceeds from gain on sale of oil and gas properties, net	360	—	—
Additions to furniture, fixtures and equipment, net	(544)	(330)	(563)
Cash used in investing activities	(284,758)	(91,346)	(29,553)
FINANCING ACTIVITIES:			
Borrowings under credit facility	246,800	121,800	67,407
Repayment of amounts outstanding under credit facility	(203,000)	(154,119)	(78,625)
Proceeds from issuance of common stock, net offering costs	122,150	101,764	—
Proceeds from issuance of common stock upon exercise of stock options	1,009	751	—
Loan origination fees	(1,116)	(448)	(400)
Cash provided by (used in) financing activities	165,843	69,748	(11,618)
CHANGE IN CASH AND CASH EQUIVALENTS	(23,145)	20,779	(1,410)
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	(19)	1	18
CASH AND CASH EQUIVALENTS, beginning of year	23,465	2,685	4,077
CASH AND CASH EQUIVALENTS, end of year	$ 301	$ 23,465	$ 2,685
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 2,856	$ 1,920	$ 1,790
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Acquisition of oil and gas properties	$ 547	$ 132	$ —
Asset retirement obligations capitalized	$ 1,190	$ 604	$ 170

See accompanying notes to these consolidated financial statements.

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

Approach Resources Inc. ("Approach," the "Company," "we," "us" or "our") is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on finding and developing oil and natural gas reserves in oil shale and tight sands. Our properties are primarily located in the Permian Basin in West Texas. We also own interests in the East Texas Basin.

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, which affect our estimate of depletion expense as well as our impairment analyses. Significant assumptions also are required in our estimation of accrued liabilities, 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.

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, accounts payable and accrued liabilities and long-term debt approximate fair value, as of December 31, 2011 and 2010. 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, 2011	December 31, 2010
Mineral interests in properties:		
Unproved properties	$ 46,813	$ 19,963
Proved properties	26,845	15,317
Wells and related equipment and facilities	626,564	430,810
Support equipment	5,135	3,098
Uncompleted wells, equipment and facilities	27,302	5,729
Total costs	732,659	474,917
Less accumulated depreciation, depletion and amortization	(137,980)	(106,127)
Net capitalized costs	$ 594,679	$ 368,790

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, 2011 or 2010. 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, 2011, 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 barrel of oil equivalent ("Boe"), and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas may differ significantly from the price for a barrel of oil. Depreciation, depletion and amortization expense for oil and gas producing property and related equipment was $32.1 million, $22.0 million and $24.5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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. For 2011, we recorded an impairment expense of $15.2 million, which was attributable to our oil and gas properties in the East Texas Basin. At December 31, 2011, we had $2.7 million recorded for the East Texas Basin, which is the estimated fair value at December 31, 2011. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2010 or 2009.

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. For 2011, we recorded an impairment expense of $3.3 million, related to all of our remaining carrying costs associated with our unproved properties in Northern New Mexico. For 2010, we recorded an impairment of $2.6 million, which resulted from a write-off of $2.6 million in costs associated with our Boomerang project in Kentucky and represented the remaining carrying value we had recorded for the project. We also recorded an impairment in 2009, which resulted from a write-off of $3 million in costs associated with our British Columbia project, and represented the remaining carrying value we had recorded for the project.

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. During 2011, we sold our working interest in Northeast British Columbia for net proceeds of $360,000. The gain on the sale of this interest, net of foreign currency, was $248,000, and is included under "Other" on the consolidated statement of operations for the year ended December 31, 2011. Our carrying value and associated plugging obligations related to Northeast British Columbia previously were written off as an impairment of unproved properties during the year ended December 31, 2009.

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, 2011 or 2010.

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

Dependence on Major Customers. For the years ended December 31, 2011, 2010 and 2009, 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, 2011, and 2010. 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, services, supplies and qualified personnel. During these periods, the costs and delivery times of rigs, equipment, services and supplies are substantially greater. If the unavailability or high cost of drilling rigs, equipment, services, 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 and completion 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 or other services.

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 $372,000, $233,000 and $204,000 for the years ended December 31, 2011, 2010 and 2009, respectively.

Income Taxes. We are subject to U.S. federal income taxes along with state income taxes in Texas and New Mexico. When tax returns are filed, it is highly certain that some positions taken would be sustained upon examination by the taxing authorities, while others are subject to uncertainty about the merits of the position taken or the amount of the position that would be ultimately sustained. The benefit of a tax position is recognized in the financial statements in the period during which, based on all available evidence, management believes it is more likely than not that the position will be sustained upon examination, including the resolution of appeals or litigation processes, if any. Tax positions taken are not offset or aggregated with other positions. Tax positions that meet the more-likely-than-not recognition threshold are measured as the largest amount of tax benefit that is more than 50% likely of being realized upon settlement with the applicable taxing authority. The portion of the benefits associated with tax positions taken that exceeds the amount measured as described above is reflected as a liability for unrecognized tax benefits in the accompanying balance sheet along with any associated interest and penalties that would be payable to the taxing authorities upon examination. Interest and penalties associated with unrecognized tax benefits are classified as additional income taxes in the consolidated statement of income.

Based on our analysis, we did not have any uncertain tax positions as of December 31, 2011 or 2010. The Company's income tax returns are subject to examination by the relevant taxing authorities as follows: U.S. Federal income tax returns for tax years 2008 and forward, Texas income and margin tax returns for tax years 2008 and forward and New Mexico income tax returns for years 2008 and forward. There are currently no income tax examinations underway for these jurisdictions.

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 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 income are reclassified to oil, NGL 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 gain (loss) 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 and 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, 2011 and 2010 (in thousands):

	2011	2010
Capital expenditures accrued	$20,512	$ 8,924
Operating expenses and other	4,325	1,762
Total	$24,837	$10,686

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, 2011, 2010 and 2009.

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 income within stockholders' equity on our consolidated balance sheets. During the years ended December 31, 2011 and 2010, we recognized a translation loss of $20,000 and $4,000, net of the related income taxes, respectively. During the year ended December 31, 2009, we recognized translation gains, net of related income tax of $266,000.

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):

	For the Years Ended December 31,		
	2011	2010	2009
Income (numerator):			
Net income (loss) — basic	$ 7,242	$ 7,462	$ (5,229)
Weighted average shares (denominator):			
Weighted average shares — basic	28,930,792	22,065,797	20,869,832
Dilution effect of share-based compensation, treasury method(1)	227,806	148,273	—
Weighted average shares — diluted	29,158,598	22,214,070	20,869,832
Earnings (loss) per share:			
Basic	$ 0.25	$ 0.34	$ (0.25)
Diluted	$ 0.25	$ 0.34	$ (0.25)

(1) Approximately 410,000 options to purchase our common stock were excluded from this calculation because they were anti-dilutive, during the year ended December 31, 2009.

2. Working Interest Acquisitions

In February 2011, we acquired an additional 38% working interest in northwest Project Pangea from two non-operating partners for $70.8 million, after customary post-closing adjustments (the "38% Working Interest Acquisition"). We funded the 38% Working Interest Acquisition with cash on hand and borrowings under our revolving credit facility. Our 2011 oil, NGL and gas sales and net income included approximately $25.5 million and $8.4 million, respectively, related to this acquisition.

In October 2010, we acquired an additional 10% working interest in northwest Project Pangea from a non-operating partner for $21.2 million, after post-closing adjustments (the "10% Working Interest Acquisition"). Funding was provided through borrowings under our revolving credit facility. Our 2010 oil, NGL and gas sales and net income included approximately $1.3 million and $477,000, respectively, related to this acquisition.

The following table represents the allocation of the total purchase price of the 38% Working Interest Acquisition and the 10% Working Interest Acquisition (in thousands).

	38% Working Interest Acquisition	10% Working Interest Acquisition
Purchase price:		
Acquisition price	$76,000	$21,500
Asset retirement obligations assumed	547	132
Post-closing purchase price adjustments	(5,720)	(453)
Total	$70,827	$21,179
Allocation:		
Wells, equipment and related facilities	$51,447	$15,613
Mineral interests in oil and gas properties	19,380	5,566
Total	$70,827	$21,179

The following condensed unaudited pro forma information gives effect to these acquisitions as if they had occurred on January 1, 2009. The pro forma information has been included in the notes as required by U.S. generally accepted accounting principles 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 these acquisitions been effective on the dates as indicated and should not be viewed as indicative of operations in the future.

	Unaudited Pro Forma Financial Data		
	Years Ended December 31,		
	2011	2010	2009
	(dollars in thousands, except per-share amounts)		
Oil, NGL and gas sales	$113,041	$86,114	$57,221
Total operating expenses	$100,125	$63,384	$63,333
Net income (loss)	$ 7,186	$15,714	$ (5,207)
Earnings (loss) per share — basic	$ 0.25	$ 0.71	$ (0.25)
Earnings (loss) per share — diluted	$ 0.25	$ 0.71	$ (0.25)

3. Public Equity Offerings

On November 15, 2011, we completed a public offering of 4,000,000 shares of our common stock. The underwriters were granted an option to purchase up to 600,000 additional shares of our common stock. The underwriters fully exercised this option and purchased the additional shares on November 16, 2011. After deducting underwriting discounts and transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We intend to use the proceeds to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used the proceeds of the 2011 equity offering to repay outstanding borrowings under our revolving credit facility.

On November 10, 2010, we completed a public offering of 5,750,000 shares of our common stock. The underwriters were granted an option to purchase up to 862,500 additional shares of our common stock. The underwriters fully exercised this option and purchased the additional shares on November 11, 2010. After deducting underwriting discounts and transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million. We used the proceeds of the 2010 equity offering to repay all outstanding borrowings under our revolving credit facility, and to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs.

4. Revolving Credit Facility

We have a $300 million revolving credit facility with a borrowing base set at $260 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.

The maturity date under our revolving credit facility is July 31, 2014. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

Effective May 4, 2011, we entered into a tenth amendment (the "Tenth Amendment") to our credit agreement, which (i) increased the borrowing base under the credit agreement to $200 million from $150 million, (ii) increased the lenders' aggregate maximum commitment to $300 million from $200 million, (iii) extended the maturity date of the credit agreement by two years to July 31, 2014, (iv) increased the consolidated funded debt to consolidated EBITDAX ratio covenant to a ratio of not more than 4 to 1 from a ratio of not more than 3.5 to 1, (v) permitted the issuance of up to $200 million of senior unsecured debt; provided, that any such debt issuance will reduce the borrowing base by 25% of the principal amount of the issuance, and (vi) added a fifth bank, Royal Bank of Canada, to the lending group.

The Tenth Amendment also revised the applicable rate schedule to decrease the Eurodollar rate margin to a range of 1.75% to 2.75% from a range of 2.25% to 3.25% and decreased the base rate margin to a range of 0.75% to 1.75% from a range of 1.25% to 2.25%, each determined by the then-current percentage of the borrowing base that is drawn.

Effective October 7, 2011, we entered into an eleventh amendment to our credit agreement, which, among other things, (i) increased the borrowing base to $260 million from $200 million, and (ii) added Wells Fargo Bank, N.A. as a sixth lender to the bank syndicate.

Effective December 21, 2011, we entered into a twelfth amendment to our credit agreement, which assigned the rights and obligations of BNP Paribas as lender under the credit agreement, to JPMorgan Chase Bank, N.A., KeyBank National Association, Royal Bank of Canada and Wells Fargo Bank, N.A.

We had outstanding borrowings of $43.8 million under our revolving credit facility at December 31, 2011. We had no outstanding borrowings at December 31, 2010. The interest rate applicable to our revolving credit facility at December 31, 2011, was 3.7%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at December 31, 2011, 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.

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 4.0 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 noncash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or nonrecurring 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 defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At December 31, 2011, 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 $4.7 million, $2.6 million and $1.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. Such amounts represent the estimated fair value of stock awards for which the requisite service period elapsed during those periods. Included in share-based compensation expense for the years ended December 31, 2011, 2010 and 2009, was $420,000, $381,000 and $377,000, respectively, related to grants to nonemployee directors.

Stock Options

There were no stock option grants during the years ended December 31, 2011, 2010 and 2009. As of December 31, 2011, all stock options are fully vested.

The following table summarizes stock options outstanding and activity as of and for the years ended December 31, 2011, 2010 and 2009, (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, 2009	434,302	$ 8.47	6.55	$ 837
Granted	—	$ —		
Exercised	—	$ —		
Canceled	(24,975)	$12.00		
Outstanding at December 31, 2009	409,327	$ 8.03	5.41	$ —
Granted	—	$ —		
Exercised	(58,798)	$12.76		
Canceled	(16,191)	$12.00		
Outstanding at December 31, 2010	334,338	$ 7.01	3.85	$4,567
Granted	—	—		
Exercised	(74,241)	$13.59		
Canceled	—	—		
Outstanding at December 31, 2011	260,097	$ 5.13	1.94	$6,315
Exercisable (fully vested) at December 31, 2011	260,097	$ 5.13	1.94	$6,315

The intrinsic value of the options exercised during the years ended December 31, 2011 and 2010, was $1.1 million and $608,000, respectively. The tax benefit recognized related to the stock option exercises was $358,000 and $141,000 in the years ended December 31, 2011, and 2010, respectively.

Nonvested Shares

Share grants totaling 256,317 shares, 568,142 shares and 204,790 shares with an approximate aggregate fair market value of $8.1 million, $4.3 million and $1.7 million at the time of grant were granted to employees during the years ended December 31, 2011, 2010 and 2009, respectively. Included in the share grants for 2011 and 2010 are 204,000 shares and 400,000 shares, respectively, awarded to our executive officers. The aggregate fair market value of these shares on the grant date was $6.5 million and $2.7 million, respectively, to be expensed over a remaining service period of approximately three years, subject to certain performance restrictions. A summary of the status of nonvested shares for the years ended December 31, 2011, 2010 and 2009, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2009	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
Granted	568,142	7.71
Vested	(77,969)	10.07
Canceled	(7,272)	9.51
Nonvested at December 31, 2010	708,781	8.04
Granted	256,317	31.54
Vested	(124,134)	9.93
Canceled	(50,842)	12.03
Nonvested at December 31, 2011	790,122	$15.06

As of December 31, 2011, unrecognized compensation expense related to the nonvested shares amounted to $7.6 million, which will be recognized over a remaining service period of three years.

On February 21, 2012, 129,890 restricted shares were awarded to our executive officers. The number of shares awarded assumes that the Company will achieve maximum total shareholder return performance conditions. The aggregate fair market value of these shares on the grant date was $4.8 million, to be expensed over a remaining service period of approximately four years, subject to certain performance conditions and three-year total shareholder return performance.

6. Income Taxes

Our provision (benefit) for income taxes comprised the following (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Deferred:			
Federal	$3,199	$3,917	$(1,056)
State	289	183	271
Total deferred provision (benefit) for income taxes	$3,488	$4,100	$ (785)

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. Federal statutory tax rates to pre-tax income (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Statutory tax at 34%	$3,648	$3,931	$(2,045)
State taxes, net of federal impact	289	184	72
Permanent differences(1)	(289)	53	231
Other differences	(160)	(68)	957(2)
Total	$3,488	$4,100	$ (785)

(1) Amounts primarily relate to share-based compensation expense and stock option exercises.

(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 $46.3 million and $44.6 million at December 31, 2011 and 2010, respectively. At December 31, 2011 and 2010, $504,000 and $2.3 million of deferred taxes expected to be realized within one year were included in current assets. Significant components of net deferred tax assets and liabilities are (in thousands):

	Years Ended December 31,	
	2011	2010
Deferred tax assets:		
Net operating loss carryforwards	$ 31,052	$ 13,587
Unrealized loss on commodity derivatives	504	381
Other	866	1,148
Total deferred tax assets	32,422	15,116
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods—oil and gas properties	(78,174)	(57,414)
Net deferred tax liability	$(45,752)	$(42,298)

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

Expiration Dates	Amounts	Stock Option Adjustments	Total
2023	$ 1,523	$ —	$ 1,523
2024	1,082	—	1,082
2025	2,594	—	2,594
2026	1,683	—	1,683
2027	1,020	—	1,020
2028	1,308	—	1,308
2029	3,299	—	3,299
2030	12,605	—	12,605
2031	63,705	1,972	65,677
Total	$88,819	$1,972	$90,791

As of December 31, 2011, we had net operating loss carryfowards of approximately $90.8 million, of which approximately $2 million was generated from the benefit of stock options. When these benefits are realized, they will be credited to additional paid-in capital.

7. Derivatives

At December 31, 2011, we had the following commodity derivatives positions outstanding:

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Natural Gas – 2012	Call	230,000 MMBtu/month	$6.00/MMBtu
Crude Oil – 2012	Collar	700 Bbls/d	$85.00/Bbl – $97.50/Bbl
Crude Oil – 2012	Collar	500 Bbls/d	$90.00/Bbl – $106.10/Bbl

Subsequent to December 31, 2011, we entered into the following commodity derivatives positions:

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Natural Gasoline – February 2012 – December 2012	Swap	225 Bbls/d	$95.55/Bbl
Normal Butane – March 2012 – December 2012	Swap	225 Bbls/d	$73.92/Bbl
Crude Oil – 2013	Collar	650 Bbls/d	$90.00/Bbl – $105.80/Bbl
Crude Oil – 2014	Collar	550 Bbls/d	$90.00/Bbl – $105.50/Bbl

The following summarizes the fair value of our open commodity derivatives as of December 31, 2011 and December 31, 2010 (in thousands):

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	December 31, 2011	December 31, 2010	Balance Sheet Location	December 31, 2011	December 31, 2010
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives	$—	$862	Unrealized loss on commodity derivatives	$1,441	$1,956

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

	Income Statement Location	Year Ended December 31, 2011	2010	2009
Derivatives not designated as hedging instruments				
Commodity derivatives	Unrealized (loss) gain on commodity derivatives	$ (347)	$ 788	$ (9,899)
	Realized gain on commodity derivatives	3,375	5,784	14,659
		$3,028	$6,572	$ 4,760

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 value 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 option 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, 2011, 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, 2011, 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, 2011, our Level 3 measurements were limited to our asset retirement obligation. Additionally, Level 3 measurements were used to calculate our estimated fair value of our oil and gas properties in the East Texas Basin. We valued these properties by estimating future discounted net cash flows of reserves using forward market prices adjusted for locational basis differentials and other costs.

8. Commitments and Contingencies

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 daywork drilling contracts was $3.4 million at December 31, 2011.

In December 2011, we extended an 18-month contract for a dedicated, third-party fracture stimulation fleet by three months. The contract requires a minimum commitment of $16.5 million per quarter for the contract term. The contract contains early termination provisions for a monthly fee of less than the minimum quarterly commitment in the event of a termination before the end of the contract term.

At December 31, 2011, we had employment agreements with all five of our executive 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 executives covered by these agreements were each terminated without cause, was approximately $4 million at December 31, 2011. This estimate assumes the maximum potential bonus for 2012 is earned by each employee during 2012.

We lease our office space in Fort Worth, Texas, under a non-cancelable agreement that expires on December 31, 2012. 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 as of December 31, 2011 (in thousands):

2012	$510
2013 – 2016	125
Total	$635

Rent expense under our lease arrangements amounted to $630,000, $463,000 and $461,000 for the years ended December 31, 2011, 2010 and 2009, respectively.

Litigation

In August 2011, we settled all claims with EnCana Oil & Gas (USA) Inc. ("EnCana") arising out of *Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A*, District Court of Limestone County, Texas. As previously disclosed, on July 2, 2009, our operating subsidiary filed a lawsuit against EnCana for breach of the joint operating agreement ("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. As part of the release and settlement of all claims by both parties, EnCana paid us $1.4 million. In addition, we will remain operator of the North Bald Prairie project, subject to the terms of the JOA.

We are involved in various 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.

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.

9. 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,		
	2011	2010	2009
Property acquisition costs:			
Unproved properties	$ 30,019	$12,528	$ 1,081
Proved properties	11,785	2,055	57
Exploration costs	9,991	2,874	1,483
Development costs(1)	233,969	72,528	28,121
Total costs incurred	$285,764	$89,985	$30,742

(1) For the years ended December 31, 2011, 2010 and 2009, development costs include $1.2 million, $604,000 and $170,000 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,		
	2011	2010	2009
Revenues	$108,387	$ 57,581	$ 40,648
Production costs	(19,134)	(11,545)	(9,773)
Exploration expense	(9,546)	(2,589)	(1,621)
Impairment	(18,476)	(2,622)	(2,964)
Depletion	(31,858)	(21,991)	(24,456)
Income tax expense	(9,546)	(6,527)	(636)
Results of operations	$ 19,827	$ 12,307	$ 1,198

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

Proved Reserves

The estimates of proved reserves and related valuations for the years ended December 31, 2011, 2010 and 2009, 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 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, NGL and natural gas reserves for the years ended December 31, 2009, 2010 and 2011, are as follows:

Proved Developed and Proved Undeveloped Reserves	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance — December 31, 2008	3,538	2,829	172,867	35,178
Extensions and discoveries	1,392	1,290	14,301	5,066
Purchases of minerals in place	—	—	—	—
Production	(206)	(209)	(6,320)	(1,468)
Revisions to previous estimates	(386)	184	(12,514)	(2,288)
Balance — December 31, 2009	4,338	4,094	168,334	36,488
Extensions and discoveries	984	1,395	8,365	3,773
Purchases of minerals in place	383	786	4,736	1,958
Production	(247)	(261)	(6,290)	(1,556)
Revisions to previous estimates	(507)	14,685	(24,756)	10,052
Balance — December 31, 2010	4,951	20,699	150,389	50,715
Extensions and discoveries	11,847	7,010	40,146	25,548
Purchases of minerals in place	2,200	4,284	24,083	10,498
Production	(482)	(798)	(6,345)	(2,338)
Revisions to previous estimates	(465)	(2,072)	(29,466)	(7,448)
Balance — December 31, 2011	18,051	29,123	178,807	76,975
Proved Developed Reserves:				
December 31, 2009	1,239	1,879	74,804	15,585
December 31, 2010	2,146	11,193	74,739	25,795
December 31, 2011	5,542	13,945	84,743	33,611

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2011, 2010 and 2009:

Year Ended December 31, 2011

We produced 2.4 MMBoe during 2011, 99% of which is attributable to our assets in the Permian Basin. Extensions and discoveries of 25.5 MMBoe for 2011 include 24.2 MMBoe attributable to our Wolffork oil shale resource play in the Permian Basin. During 2011, we acquired approximately 10.5 MMBoe of proved reserves through the 38% Working Interest Acquisition. We recorded downward revisions of 7.5 MMBoe to the December 31, 2010, estimates of our proved reserves at year end 2011. Downward revisions of 7.5 MMBoe include 5.6 MMBoe of economic revisions in southeast Project Pangea in the Permian Basin and 2.2 MMBoe of proved undeveloped reserves in the East Texas Basin that, due to ongoing, low natural gas prices, we do not expect to develop by year-end 2013. Also included in the revisions were 0.3 MMBoe of positive revisions resulting from higher oil and NGL prices using the average 12-month price in 2011.

Year Ended December 31, 2010

Our drilling programs in Project Pangea in the Permian Basin 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, 2010, we recorded a 10.1 MMBoe positive revision to our previous estimate, resulting from 9.2 MMBoe attributable to planned processing upgrades in southeast Project Pangea and 1.1 MMBoe attributable to an increase in commodity prices, partially offset by 0.2 MMBoe of negative performance revisions. On April 1, 2011, we will begin realizing NGL revenues from the natural gas production in southeast Project Pangea under a gas purchase and processing contract with DCP Midstream, LP. The commodity prices used to estimate our proved reserves at December 31, 2010, increased to $4.38/MMBtu of gas, $39.25/Bbl of NGLs and $79.40/Bbl of oil from $3.87/MMBtu of natural gas, $27.20/Bbl of NGLs and $56.04/Bbl of oil at December 31, 2009. The negative revision of 0.1 MMBoe, primarily related to producing properties in our North Bald Prairie field in the East Texas Basin. Well performance data collected during 2010 for North Bald Prairie indicated that these assets underperformed our year-end 2010 decline estimates. Accordingly, we removed 0.9 Bcf (0.2 MMBoe) from proved reserves recorded for North Bald Prairie. We also removed 0.1 MMBoe in Project Pangea due to performance revisions.

Year Ended December 31, 2009

Our drilling programs in Project Pangea in the Permian Basin 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 2.3 MMBoe downward revision of our previous estimate, 1.7 MMBoe and 0.6 MMBoe 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 the East Texas Basin. Well performance data collected during 2009 for North Bald Prairie indicate that these assets underperformed our year-end 2008 decline estimates. Accordingly, we removed 4.5 Bcf from proved reserves recorded for North Bald Prairie. We also removed 0.1 MMBoe in southeast Project Pangea due to performance revisions. Partially offsetting the removal of 0.9 MMBoe from proved reserves recorded for North Bald Prairie and southeast Project Pangea was a positive performance revision of 0.3 MMBoe in northern Project Pangea.

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 2010 and 2009 provisions of ASC 932 and SFAS 69. Future cash inflows were computed by applying the average on the closing price on the first day of each month for the 12-month period prior to December 31, 2011, 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 pre-tax 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,		
	2011	2010	2009
Future cash flows	$ 3,772,633	$1,804,477	$1,007,703
Future production costs	(1,012,044)	(499,321)	(358,276)
Future development costs	(625,994)	(259,005)	(213,161)
Future income tax expense	(583,961)	(282,628)	(88,796)
Future net cash flows	1,550,634	763,523	347,470
10% annual discount for estimated timing of cash flows	(1,136,253)	(559,291)	(267,479)
Standardized measure of discounted future net cash flows	$ 414,381	$ 204,232	$ 79,991

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,		
	2011	2010	2009
Balance, beginning of period	$ 204,232	$ 79,991	$142,635
Net change in sales and transfer prices and in production (lifting) costs related to future production	334,104	120,520	(89,649)
Changes in estimated future development costs	(395,037)	(65,718)	(29,647)
Sales and transfers of oil and gas produced during the period	(89,253)	(46,031)	(30,877)
Net change due to extensions, discoveries and improved recovery	291,501	30,240	26,648
Net change due to purchase of minerals in place	119,780	15,696	—
Net change due to revisions in quantity estimates	(84,988)	80,564	(12,034)
Previously estimated development costs incurred during the period	182,522	40,265	28,121
Accretion of discount	32,793	17,166	18,743
Other	(38,107)	4,171	(3,449)
Net change in income taxes	(143,166)	(72,632)	29,500
Standardized measure of discounted future net cash flows	$ 414,381	$204,232	$ 79,991

The commodity prices in effect at December 31, 2011, 2010 and 2009, inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows:

	2011	2010	2009
Oil (per Bbl)	$89.65	$74.90	$56.04
Natural gas liquids (per Bbl)	$49.63	$39.25	$27.20
Gas (per Mcf)	$ 3.97	$ 4.13	$ 3.88

11. Supplementary Data

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

	2011 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 31,123	$ 27,958	$ 29,123	$ 20,183
Net operating expenses	(42,339)	(19,092)	(18,170)	(17,930)
Interest expense, net	(1,010)	(1,016)	(863)	(513)
Realized gain on commodity derivatives	1,720	1,392	66	197
Unrealized (loss) gain on commodity derivatives	(4,168)	1,739	2,231	(149)
(Loss) gain on sale of oil and gas properties	(243)	—	3	488
(Loss) income before income (benefit) tax	(14,917)	10,981	12,390	2,276
Income tax (benefit) provision	(5,632)	3,908	4,400	812
Net (loss) income	$ (9,285)	$ 7,073	$ 7,990	$ 1,464
Basic net (loss) income applicable to common stockholders per common share	$ (0.30)	$ 0.25	$ 0.28	$ 0.05
Diluted net (loss) income applicable to common stockholders per common share	$ (0.30)	$ 0.25	$ 0.28	$ 0.05

	2010 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 16,290	$ 14,916	$ 13,155	$ 13,220
Net operating expenses	(15,493)	(12,350)	(10,191)	(12,368)
Interest expense, net	(558)	(615)	(550)	(466)
Realized gain on commodity derivatives	2,171	1,615	1,768	230
Unrealized (loss) gain on commodity derivatives	(2,094)	(312)	(1,901)	5,095
Income before income taxes	316	3,254	2,281	5,711
Income tax provision	55	1,167	730	2,148
Net income	$ 261	$ 2,087	$ 1,551	$ 3,563
Basic net income applicable to common stockholders per common share	$ 0.01	$ 0.10	$ 0.07	$ 0.17
Diluted net income applicable to common stockholders per common share	$ 0.01	$ 0.10	$ 0.07	$ 0.17

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements — (continued)

	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 derivatives	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

Approach Resources Inc.
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Exhibit Number	Description of Exhibit
2.1	Purchase and Sale Agreement dated February 23, 2011, between J. Cleo Thompson and James Cleo Thompson, Jr. L.P., Wes-Tex Drilling Company, L.P. and Approach Oil & Gas Inc. (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed March 1, 2011, and incorporated herein by reference).
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†	Amended and Restated Employment Agreement by and between Approach Resources Inc. and J. Ross Craft dated January 1, 2011 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.4†	Amended and Restated Employment Agreement by and between Approach Resources Inc. and Steven P. Smart dated January 1, 2011 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.5†	Employment Agreement by and between Approach Resources Inc. and J. Curtis Henderson dated January 1, 2011 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.6†	Employment Agreement by and between Approach Resources Inc. and Qingming Yang dated January 24, 2011 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 28, 2011, and incorporated herein by reference).
10.7†	Employment Agreement by and between Approach Resources Inc. and Ralph P. Manoushagian dated January 24, 2011 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed January 28, 2011, and incorporated herein by reference).
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).

Exhibit Number	Description of Exhibit
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†	Form of Restricted 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).
10.14†	Form of Performance-Based, Time-Vesting Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.14 to the Company's Annual Report on Form 10-K filed March 11, 2011, and incorporated herein by reference).
10.15†	Form of TSR-Based Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 20, 2012, and incorporated herein by reference).
10.16	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).
10.17	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).
10.18	Gas Purchase Contract dated as of January 1, 2011, between Approach Resources I, LP and Approach Oil & Gas Inc., as Seller, and DCP Midstream, LP, as Buyer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 14, 2011, and incorporated herein by reference).
*10.19	Specimen Oil and Gas Lease for University Lands.
10.20	$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).
10.21	Amendment No. 1 dated February 19, 2008, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, and JPMorgan Chase Bank, NA, 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 February 22, 2008, and incorporated herein by reference).
10.22	Amendment No. 2 dated May 6, 2008, to Credit Agreement dated as of January 18, 2008, 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 (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K filed August 28, 2008, and incorporated herein by reference).

Approach Resources Inc.
Index to Exhibits — continued

Exhibit Number	Description of Exhibit
10.23	Amendment No. 3 dated August 26, 2008, to Credit Agreement dated as of January 18, 2008, 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 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 28, 2008, and incorporated herein by reference).
10.24	Amendment No. 4 dated April 8, 2009, to Credit Agreement dated as of January 18, 2008, 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 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed April 16, 2009, and incorporated herein by reference).
10.25	Amendment No. 5 dated July 8, 2009, to Credit Agreement dated as of January 18, 2008, 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 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed July 14, 2009, and incorporated herein by reference).
10.26	Amendment No. 6 dated as of October 30, 2009, to Credit Agreement dated as of January 18, 2008, 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 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 3, 2009, and incorporated herein by reference).
10.27	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 administrative 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 February 4, 2010, and incorporated herein by reference).
10.28	Amendment No. 8 dated as of May 3, 2010, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, The Frost National Bank, BNP Paribas and KeyBank National Association, as lenders, Fortis Capital Corp., as departing lender 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 May 6, 2010, and incorporated herein by reference).
10.29	Amendment No. 9 dated as of October 21, 2010, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, The Frost National Bank, BNP Paribas 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 October 26, 2010, and incorporated herein by reference).

Approach Resources Inc.
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Exhibit Number	Description of Exhibit
10.30	Amendment No. 10 dated as of May 4, 2011, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, The Frost National Bank, BNP Paribas, KeyBank National Association and Royal Bank of Canada, 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 May 4, 2011, and incorporated herein by reference).
10.31	Amendment No. 11 dated as of October 7, 2011, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, The Frost National Bank, BNP Paribas, KeyBank National Association, Royal Bank of Canada and Wells Fargo Bank, N.A., 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 October 11, 2011, and incorporated herein by reference).
10.32	Amendment No. 12 dated as of December 20, 2011, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, KeyBank National Association, The Frost National Bank, Royal Bank of Canada and Wells Fargo Bank, N.A., as lenders, BNP Paribas, as departing lender, 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 December 21, 2011, 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 (filed as Exhibit 21.1 to the Company's Annual Report on Form 10-K filed March 13, 2010, and incorporated herein by reference).
*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.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema Document.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document.

Approach Resources Inc.
Index to Exhibits — continued

Exhibit Number	Description of Exhibit
*101. PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
*101. DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.

† Denotes management contract or compensatory plan or arrangement.

Supplemental Non-GAAP Financial Information

This annual report to stockholders contains certain financial measures that are non-GAAP financial measures within the meaning of Regulation G. We have provided reconciliations below of each non-GAAP financial measure presented herein to its most directly comparable GAAP financial measure. Please note that the non-GAAP financial measures presented herein may not be comparable to similarly titled measures used by other companies, including the Company's peers. We encourage you to review the non-GAAP financial measures presented herein along with the Company's audited financial statements for the year ended December 31, 2011, which are included in the immediately preceding Form 10-K. If you are not familiar with the oil and gas terms or abbreviations used in this supplement, please refer to the definitions of these terms and abbreviations under the caption "Glossary and Selected Abbreviations" at the end of Item 15 of our annual report on Form 10-K filed with the SEC on March 12, 2012.

Adjusted Net Income and Adjusted Net Income per Diluted Share

Adjusted net income and adjusted net income per diluted share exclude (1) impairment expense, (2) unrealized, pre-tax gain or loss on commodity derivatives, (3) loss or gain on sale of oil and gas properties and (4) 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 and adjusted net income per diluted share to net income for the years ended December 31, 2011, 2010 and 2009 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2011	2010	2009
Net income (loss)	$ 7,242	$7,462	$(5,229)
Adjustments for certain non-cash items:			
Impairment	18,476	2,622	2,964
Unrealized (gain) loss on commodity derivatives	347	(788)	9,899
Loss (gain) on sale of oil and gas properties, net of foreign currency transaction loss	(248)	—	—
Related income tax effect	(6,316)	(623)	(4,373)
Adjusted net income	$19,501	$8,673	$ 3,261
Adjusted net income per diluted share	$ 0.67	$ 0.39	$ 0.16

EBITDAX and EBITDAX per Diluted Share

We define EBITDAX as net income, plus (1) exploration expense, (2) impairment expense, (3) depletion, depreciation and amortization expense, (4) share-based compensation expense, (5) unrealized loss (gain) on commodity derivatives, (6) loss (gain) on sale of oil and gas properties, (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 and EBITDAX per diluted share below were computed in accordance with GAAP. EBITDAX is presented in this annual report and reconciled to the GAAP measure of net 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. 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 EBITDAX and EBITDAX per diluted share to net income for the years ended December 31, 2011, 2010 and 2009 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2011	2010	2009
Net income (loss)	$ 7,242	$ 7,462	$ (5,229)
Exploration	9,546	2,589	1,621
Impairment	18,476	2,622	2,964
Depletion, depreciation and amortization	32,475	22,224	24,660
Share-based compensation	4,683	2,628	1,826
Unrealized loss (gain) on commodity derivatives	347	(788)	9,899
Loss (gain) on sale of oil and gas properties, net of foreign currency transaction loss	(248)	—	—
Interest expense, net	3,402	2,189	1,787
Income tax provision (benefit)	3,488	4,100	(785)
EBITDAX	$79,411	$43,026	$36,743
EBITDAX per diluted share	$ 2.72	$ 1.94	$ 1.75

2011 Production Replacement

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

We use the production replacement ratio 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 replacement is calculated by dividing reserve extensions and discoveries of 25.5 MMBoe by production of 2.3 MMBoe. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent. NGLs are converted at a rate of one barrel of NGLs to one barrel of oil equivalent.

Reserve summary (MBoe)	
Balance — December 31, 2010	50,715
Extensions and discoveries	25,548
Purchases of minerals in place	10,498
Production	(2,338)
Revisions to previous estimates	(7,448)
Balance — December 31, 2011	76,975
Production replacement ratio	
Drill-bit	1,093%
(Extensions and discoveries / Production)	

Finding and Development Costs

All-in finding and development ("F&D") costs are calculated by dividing the sum of property acquisition costs, exploration costs and development costs for the year by the sum of reserve extensions and discoveries, purchases of minerals in place and total revisions for the year.

Drill-bit 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.

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 Boe 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), included in our SEC filings. 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, 2011, to the information required by paragraphs 11 and 21 of ASC 932-235. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent. NGLs are converted at a rate of one barrel of NGLs to one barrel of oil equivalent. Amounts in $/Boe may be converted to $/Mcfe at a rate of six to one ($0.06 per Boe equals $0.01 per Mcfe). Amounts may not convert exactly in all cases due to rounding.

Cost summary (in thousands)	
Property acquisition costs	
Unproved properties	$ 17,361
Proved properties	5,063
Working interest acreage acquisition	19,380
Working interest acquisition costs	51,447
Exploration costs	9,991
Development costs	182,522
Total costs incurred	$285,764
Reserve summary (MBoe)	
Balance — December 31, 2010	50,715
Extensions and discoveries	25,548
Purchases of minerals in place	10,498
Production	(2,338)
Revisions to previous estimates	(7,448)
Balance — December 31, 2011	76,975
Finding and development costs ($/Boe)	
All-in F&D cost	$ 9.99
Drill-bit F&D cost	$ 7.54

CORPORATE DATA

BOARD OF DIRECTORS

BRYAN H. LAWRENCE
Chairman of the Board of Directors

J. ROSS CRAFT
President, Chief Executive Officer and Director

ALAN D. BELL[1]
Director, Audit Committee Chairman

JAMES H. BRANDI[1][2]
Director, Compensation and Nominating Committee Chairman

JAMES C. CRAIN[1][2]
Director

SHELDON B. LUBAR[2]
Director

CHRISTOPHER J. WHYTE[1]
Director

[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

QINGMING YANG
Executive Vice President – Business Development and Geosciences

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

CORPORATE HEADQUARTERS

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STOCK LISTING

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

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Dallas, Texas

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Thompson & Knight LLP
Dallas, Texas

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WEBSITE

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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: Investor Relations, One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116, 817.989.9000.

Approach
Resources Inc.

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