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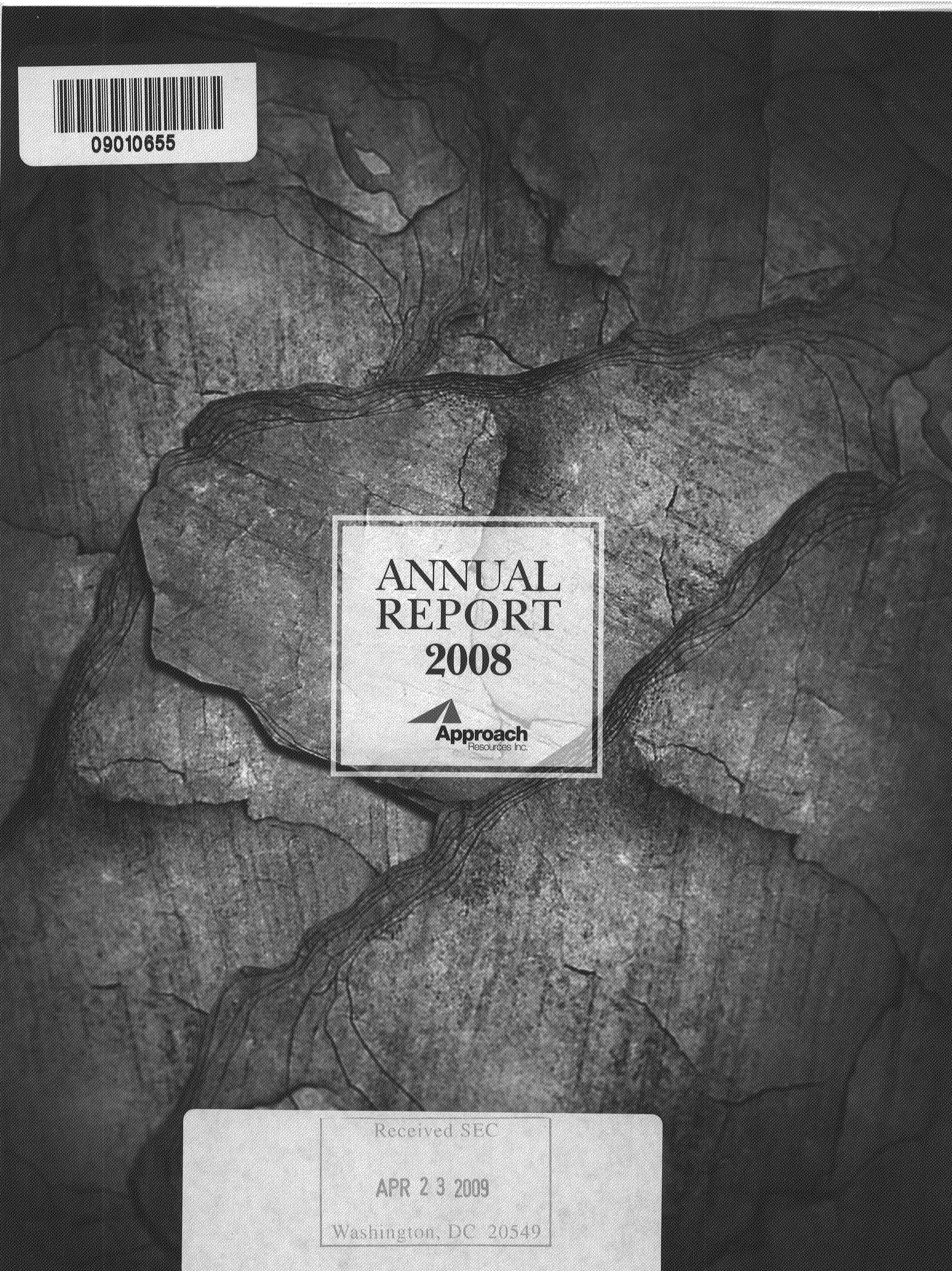


ANNUAL REPORT 2008

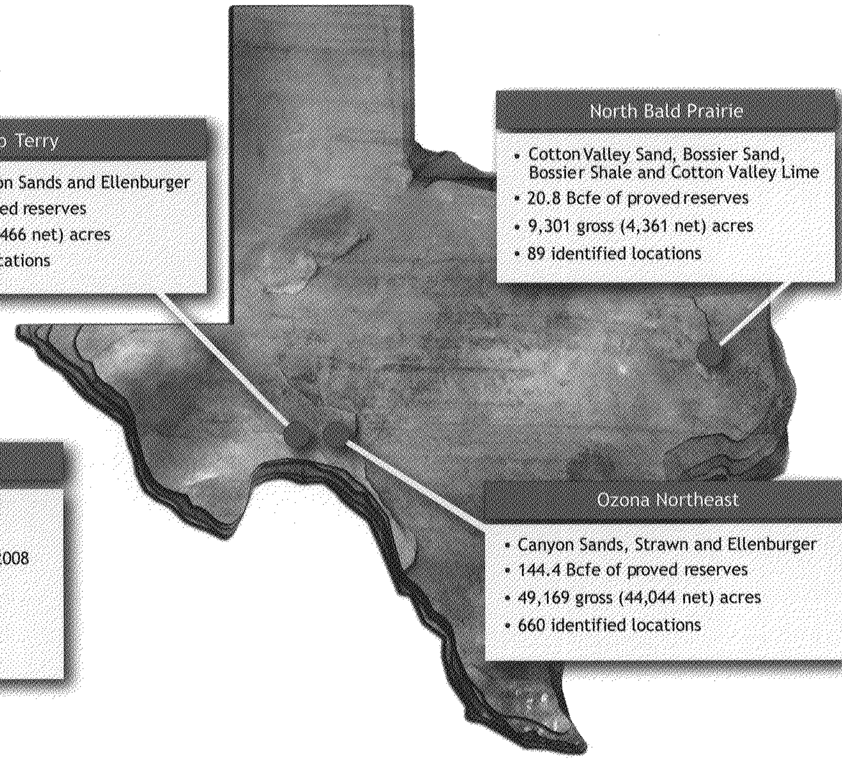
Approach Resources Inc.

Received SEC

APR 2 3 2009

Washington, DC 20549

Core Areas of Operation



Cinco Terry

- Wolfcamp, Canyon Sands and Ellenburger
- 45.9 Bcfe of proved reserves
- 45,288 gross (19,466 net) acres
- 456 identified locations

North Bald Prairie

- Cotton Valley Sand, Bossier Sand, Bossier Shale and Cotton Valley Lime
- 20.8 Bcfe of proved reserves
- 9,301 gross (4,361 net) acres
- 89 identified locations

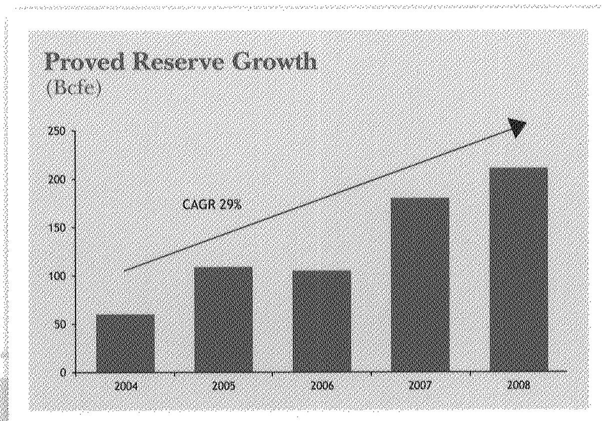
Portfolio Highlights

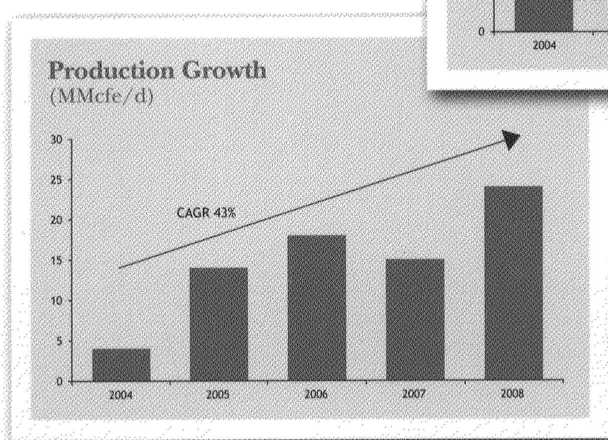
- 211.1 Bcfe of proved reserves
- 48% proved developed, 82% natural gas
- 24 MMcfe/d average daily production for 2008
- 20+ year reserve life index
- 300,334 gross (199,818 net) acres
- 1,205 identified drilling locations
- 445 producing wells

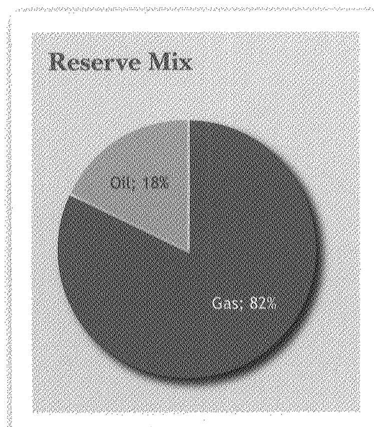
Ozona Northeast

- Canyon Sands, Strawn and Ellenburger
- 144.4 Bcfe of proved reserves
- 49,169 gross (44,044 net) acres
- 660 identified locations

Production and Reserves







Information related to core areas of operation and reserve mix is as of December 31, 2008. 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, 2008, which was filed with the Securities and Exchange Commission on March 13, 2009.

Financial and Operating Data

(thousands, except per-unit and per-share metrics)

	2008	2007	2006
Revenues (in thousands):			
Gas	$ 58,819	$ 33,497	$ 41,851
Oil	16,413	5,062	4,821
NGLs	4,637	555	–
Total oil and gas sales	79,869	39,114	46,672
Realized gain on commodity derivatives	2,936	4,732	6,222
Total oil and gas sales including derivative impact	$ 82,805	$ 43,846	$ 52,894
Production:			
Gas (MMcf)	7,092	4,801	6,282
Oil (MBbls)	175	72	77
NGLs (MBbls)	102	12	–
Total (MMcfe)	8,755	5,305	6,744
Total (MMcfe/d)	23.9	14.5	18.5
Average prices:			
Gas (per Mcf)	$ 8.29	$ 6.98	$ 6.66
Oil (per Bbl)	93.79	70.31	62.65
NGLs (per Bbl)	45.46	46.25	–
Total (per Mcfe)	9.12	7.37	6.92
Realized gain on commodity derivatives (per Mcfe)	0.34	0.89	0.92
Total per Mcfe including derivative impact	9.46	8.26	7.84
Costs and expenses (per Mcfe):			
Lease operating	$ 0.87	$ 0.72	$ 0.58
Severance and production taxes	$ 0.48	$ 0.31	$ 0.26
Exploration	$ 0.17	$ 0.17	$ 0.24
Impairment of non-producing properties	$ 0.73	$ 0.05	$ 0.08
General and administrative	$ 1.01	$ 2.39	$ 0.36
Depletion, depreciation and amortization	$ 2.71	$ 2.47	$ 2.16
Financial highlights:			
Net income	$ 23,386	$ 2,709	$ 21,202
Earnings per diluted share	$ 1.12	$ 0.24	$ 2.20
Adjusted net income*	$ 23,483	$ 5,286	$ 15,849
Adjusted earnings per diluted share*	$ 1.13	$ 0.47	$ 1.64
EBITDAX*	$ 63,201	$ 30,351	$ 44,887
EBITDAX per diluted share*	$ 3.03	$ 2.71	$ 4.66
Weighted average shares outstanding	20,825	11,184	9,635
Total long-term debt	$ 43,537	$ –	$ 47,619
Stockholders' equity	$ 223,813	$ 199,819	$ 69,572
Total assets	$ 338,241	$ 248,726	$ 150,309

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

Stockholders' Letter

April 24, 2009

Dear Fellow Stockholders,

2008 was a volatile year, as we watched natural gas prices soar to a mid-year high of $13.58 per MMBtu followed by a 61% decline, ending the year at $5.29 per MMBtu. Further, during the third quarter of 2008, an estimated 340 MMcfe of production was shut-in or curtailed in Ozona Northeast, our largest-producing field, due to Hurricane Ike and the rupture of a third-party pipeline. Despite the rise and fall of commodity prices and the effects of shut-in or curtailed production, we grew our reserve base, increased production and, most importantly, maintained our financial flexibility.

Financial and operational highlights for the year included:

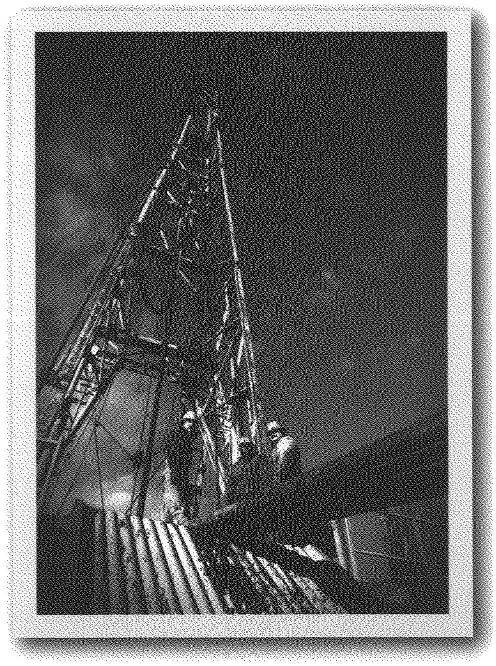
- **Proved reserves increased 17% to 211.1 Bcfe**
- **Production increased 65% to 8.8 Bcfe, or 23.9 MMcfe/d**
- **Revenues increased 104% to $79.9 million**
- **Net income increased 763% to $23.4 million, or $1.12 per diluted share**

At December 31, 2008, our total proved reserves were 211.1 Bcfe, composed of 82% natural gas and 18% oil, condensate and natural gas liquids. This represented a 17% increase from year-end 2007 proved reserves of 180.4 Bcfe. From drilling alone, we replaced 483% of production and had a drill-bit finding and development cost of $2.11 per Mcfe.[1] From all sources, we replaced 450% of production and had an all-in finding and development cost of $2.64 per Mcfe.[1]

During the first half of 2008, we focused our capital expenditures on securing the deep rights in Ozona Northeast, increasing our acreage position in Cinco Terry and continuing to develop our core properties. We closely monitored our capital program, and when commodity prices began to decline, we shifted our capital focus to our highest rate of return projects, targeting the Canyon

Sands and Ellenburger formations in Cinco Terry and initiating a Canyon Sands recompletion program in Cinco Terry and Ozona Northeast. We believe our flexibility and responsiveness to commodity and market conditions in 2008 will continue to benefit us throughout 2009.

During 2008, we expanded our Cinco Terry acreage position from 21,900 gross (9,507 net) acres as of December 31, 2007 to 45,288 gross (19,466 net) acres at December 31, 2008. As a result, our Cinco Terry field now rivals the size and, we believe, potential of our Ozona Northeast field. In 2008, we drilled 58 total wells in Cinco Terry (of which 51 were successful), recompleted six wells and ended 2008 with 45.9 Bcfe of proved reserves, a 151% increase over year-end 2007 reserves of 18.3 Bcfe. Our team has identified over 450 drilling locations in Cinco Terry, of which 89 are proved.



In 2008, we acquired an additional 95% working interest in all depths below the top of the Strawn formation and 7.7 Bcfe of proved reserves in our legacy asset, Ozona Northeast. We also acquired a compression facility and 75 miles of complementary gathering lines. In addition, we reprocessed our 3-D seismic data originally shot across Ozona Northeast in 2004 and re-interpreted our geologic model. Early results from the new seismic data and geologic model are promising, and we believe this will facilitate reserve additions through less-costly deepening projects to the Strawn and Ellenburger as well as recompletions in the Canyon Sands. Ozona Northeast is a long-life, high-quality field with a stable decline rate and 660 identified drilling locations, of which 192 are proved.

We believe in the long-term fundamentals of natural gas, an abundant, affordable, clean-burning energy source for North America. Although our

2009 activity level will be scaled back due to uncertainties in the commodity and financial markets, we remain excited about the opportunities 2009 will offer. We believe we can ride commodity price cycles with our asset base while maintaining our financial flexibility. We will continue to remain responsive to commodity and market conditions while evaluating opportunities that emphasize our expertise in developing unconventional reserves. While I can't predict the length of this downward price cycle of natural gas, I believe that we have taken the necessary steps to minimize its impact. I would like to thank our employees, business partners and fellow stockholders for your confidence in and support of AREX.

Sincerely,

J. Ross Craft
Director, President and Chief Executive Officer

[1]Drill-bit and all-in finding and development costs are non-GAAP financial measures. Reconciliations and other information on non-GAAP financial measures and production ratios 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.

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, 2008

or

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

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 W. Freeway, Suite 800 Fort Worth, Texas	**76116**
(Address of principal executive office)	*(Zip code)*

SEC Mail Processing Section
APR 23 2009
Washington, DC 101

(817) 989-9000

(Registrant's telephone number, including area code)

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 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. (Check one):

Large accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company)
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, 2008 (based on the closing price on the Nasdaq Global Market on such date) was $273.4 million. The number of shares of the registrant's common stock, par value $0.01, outstanding as of March 6, 2009 was 20,731,429.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2009 annual meeting of stockholders are incorporated by reference in Part III, Items 10-14 of this report.

APPROACH RESOURCES INC.

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

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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. 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, income and capital spending. When we use the words "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project" or their negatives, other similar expressions or the statements that include those words, it usually is a forward-looking statement.

The forward-looking statements contained in this report 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 do not intend 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:

- global economic and financial market conditions,
- our business strategy,
- estimated quantities of oil and gas reserves,
- uncertainty of commodity prices in oil and gas,
- continued disruption of credit and capital markets,
- our financial position,
- our cash flow and liquidity,
- replacing our oil and gas reserves,
- our inability to retain and attract key personnel,
- uncertainty regarding our future operating results,
- uncertainties in exploring for and producing oil and gas,
- high costs, shortages, delivery delays or unavailability of drilling rigs, equipment, labor or other services,
- disruptions to, capacity constraints in or other limitations on the pipeline systems which deliver our gas and other processing and transportation considerations,
- our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations,
- competition in the oil and gas industry,
- marketing of oil, gas and natural gas liquids,
- exploitation or property acquisitions,
- technology,
- the effects of government regulation and permitting and other legal requirements,
- plans, objectives, expectations and intentions contained in this report that are not historical, and
- other factors discussed under Item 1A. "Risk Factors" in this report.

PART I

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

General

We are an independent energy company engaged in the exploration, development, production and acquisition of unconventional natural gas and oil properties in the United States and British Columbia. We focus on natural gas and oil reserves in tight sands and shale and have assembled leasehold interests aggregating approximately 300,334 gross (199,818 net) acres as of December 31, 2008. Our management team has a proven track record of finding and exploiting unconventional reservoirs through advanced completion, fracturing and drilling techniques. As the operator of over 90% of our production and proved reserves, we have a high degree of control over capital expenditures and other operating matters.

We currently operate or have interests in the following areas:

West Texas

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

East Texas

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

Southwest Kentucky

- Boomerang (New Albany Shale)

Northeast British Columbia

- Montney tight gas and Doig Shale

Northern New Mexico

- El Vado East (Mancos Shale)

At December 31, 2008, we owned working interests in 445 producing oil and gas wells, had estimated proved reserves of approximately 211.1 Bcfe and were producing 28.0 MMcfe/d (based on production for the month of December 2008). Our average daily net production in 2009 (through February) was 26.5 MMcfe/d.

As of December 31, 2008, all of our proved reserves and production were located in Ozona Northeast and Cinco Terry in West Texas and in North Bald Prairie in East Texas. At year end 2008, our proved reserves were 82% natural gas, 48% proved developed and had a reserve life index of over 20 years (based on 2008 production of 8,755 MMcfe). In addition to our producing wells, we have identified 1,205 total drilling locations in Ozona Northeast, Cinco Terry and North Bald Prairie at December 31, 2008, of which 312 are proved.

The standardized measure of discounted future net cash flows of our proved reserves at December 31, 2008 was $142.6 million, and our PV-10 was $221.1 million. PV-10 is a non-GAAP financial measure as defined by the Securities and Exchange Commission, or the SEC, and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because PV-10 does not include the effects of income taxes on future net revenues. See Items 1. and 2., "Business and Properties — Reconciliation of non-GAAP financial measure (PV-10)" for our definition of PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows.

In December 2008, in response to a decline in oil, gas and NGL prices and uncertain market conditions, we announced that we were reducing our capital expenditure budget to an estimated $43.8 million in 2009, compared to $100.1 million of actual capital expenditures in 2008 (including $10.3 million in exploration and development costs related to the acquisition of the deep rights in Ozona Northeast in July 2008). We have reduced the number of our operating rigs from five in June 2008 to two at February 28, 2009. We intend to fund 2009 capital expenditures (excluding any acquisitions) with internally generated cash flow, with any excess cash flow applied towards debt, working capital or strategic acquisitions. We will continue to monitor commodity prices and operating expenses to determine any further adjustments to the capital budget and, unless commodity prices strengthen, we will materially reduce our 2009 capital expenditures and number of operated rigs from the $43.8 million capital budget announced in December 2008.

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

Strategy

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

- *Continue to develop our core properties.* We intend to develop further the significant remaining potential of our Ozona Northeast, Cinco Terry and North Bald Prairie properties, where we have identified 1,205 drilling locations. We believe we have the technical expertise and operational experience to maximize the value of these properties. From 2004 through 2008, we drilled over 377 wells in our Ozona Northeast and Cinco Terry fields in West Texas, making us the second most active driller in the Canyon Sands in West Texas during that time period.
- *Increase our land holdings, reserves and production through farm-ins and drilling ventures.* Our participation in farm-ins and a joint drilling venture has allowed us to grow our acreage position and reserves in Ozona Northeast (49,169 gross and 44,044 net acres and 144.4 Bcfe of proved reserves), North Bald Prairie (9,301 gross and 4,361 net acres and 20.8 Bcfe of proved reserves) and Northeast British Columbia (31,231 gross and 7,395 net acres). Farm-ins, joint drilling or "drill-to-earn" ventures and similar agreements can allow us to develop strategic, unconventional gas and oil properties for a substantially lower initial investment than acquiring the property outright.
- *Acquire strategic assets.* We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects. We focus particularly on opportunities where we believe our reservoir management and operational expertise in unconventional gas and oil properties will enhance value and performance. We remain focused on unconventional resource opportunities, but also look at conventional opportunities based on individual project economics. In 2008, we expanded our Cinco Terry net acreage position to 45,288 gross (19,466 net) acres, from 21,900 gross (9,507 net) acres in 2007. In addition, in July 2008, we acquired an additional 95% working interest in all depths below the top of the Strawn formation, 7.7 Bcfe of proved reserves, compression facilities and rights to approximately 75 miles of gathering lines in Ozona Northeast.
- *Operate our properties as a low cost producer.* We seek to minimize our operating costs by concentrating our assets within geographic areas where we can consolidate operating control and thus create operating efficiencies. We operate over 90% of our production and proved reserves and plan to continue to operate a substantial portion of our producing properties in the future. Operating control allows us to better manage timing and risk as well as the cost of exploration and development, drilling and ongoing operations.
- *Maintain financial flexibility.* At December 31, 2008, we had $43.5 million in long-term debt outstanding under our revolving credit facility, providing us with significant financial flexibility to pursue our business strategy. At February 28, 2009, we had $47.4 million in long-term debt outstanding under our credit facility. As discussed above, in response to a decline in commodity prices and current market conditions we have reduced our expected capital expenditure budget for 2009. We will further reduce capital expenditures for 2009 unless commodity prices strengthen. We intend to fund our 2009 capital expenditure budget with internally generated cash flow, with any excess cash flow applied towards debt, working capital or strategic acquisitions.

- *Exploit our undeveloped gas and oil opportunities.* We have an estimated 257,491 gross acres of undeveloped tight gas and shale gas and oil inventory to explore and produce. On a long-term basis, we believe we can add proved reserves and production from these properties through advanced technologies, including horizontal drilling and advanced fracing and completion techniques.

Oil and gas properties and operations

West Texas

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

The Ozona Northeast field in Crockett and Schleicher counties, Texas, is our largest operating area on the basis of proved reserves and production. In 2004, we began operations in the field through a farmout arrangement and have increased our total acreage position to 49,169 gross (44,044 net) acres. Beginning with our first well in February 2004, through December 31, 2008, we have drilled 311 successful wells out of 332 total wells drilled, for a 94% success rate. As of December 31, 2008, we had estimated proved reserves of 144.4 Bcfe from Ozona Northeast.

On July 1, 2008, we acquired an additional 95% working interest in all depths below the top of the Strawn formation, compression facilities and rights to approximately 75 miles of gathering lines in Ozona Northeast. As a result of the acquisition, we now own substantially all working interests in all depths of the subsurface in Ozona Northeast and have a net revenue interest of approximately 80% in Ozona Northeast. Including the 75 miles of gathering lines acquired on July 1, 2008, we own and operate approximately 150 miles of gas gathering lines in the area.

Average daily production in 2008 from Ozona Northeast was 16.4 MMcfe/d (net), or a total of 5,975 MMcfe. Average daily production in 2009 (through February) from Ozona Northeast was 16.0 MMcfe/d (net). We have identified 660 additional drilling locations in Ozona Northeast as of December 31, 2008, of which 192 are proved.

Cinco Terry (Wolfcamp, Canyon Sands and Ellenburger)

Since late 2005, we have leased and acquired options to lease 45,288 gross (19,466 net) acres in our Cinco Terry project, two miles northwest of the Ozona Northeast border, to explore the Wolfcamp, Canyon and Ellenburger formations. As of December 31, 2008, we had estimated proved reserves of 45.9 Bcfe in Cinco Terry, compared to 18.3 Bcfe of estimated proved reserves at December 31, 2007. We have approximately a 52% working interest and 39% net revenue interest in our Cinco Terry project. Average daily production in 2008 from Cinco Terry was 6.4 MMcfe/d (net), or a total of 2,333 MMcfe. Average daily production in 2009 (through February) from Cinco Terry was 9.3 MMcfe/d (net). We have identified 456 additional drilling locations in our Cinco Terry acreage as of December 31, 2008, of which 89 are proved. We own and operate seven miles of gas gathering lines in the area.

East Texas

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

In July 2007, we entered into a joint drilling venture with EnCana Oil & Gas (USA) Inc. in the East Texas Cotton Valley/Bossier trend. As part of the joint venture, we agreed to drill up to five wells at our cost to earn a 50% working interest in approximately 9,301 gross (4,361 net) acres. We began drilling operations on the initial North Bald Prairie well in August 2007. As of December 31, 2008, we had drilled and completed 10 wells. We have a 50% working interest and approximately a 40% net revenue interest in our North Bald Prairie project. Average daily production in 2008 from North Bald Prairie was 1.2 MMcf/d, or a total of 447 MMcf. Average daily production in 2009 (through February) from North Bald Prairie was 1.2 MMcf/d (net). We believe the potential exists for producing from multiple zones in this area. Our primary targets are the Cotton Valley Sands, Bossier and Cotton Valley Lime, all unconventional tight gas formations where we believe we can apply our technical and operational expertise to successfully recover natural gas. Secondary targets include the shallower Rodessa, Pettit and Travis Peak formations. We have identified 89 potential drilling locations in North Bald Prairie as of December 31, 2008, of which 31 are proved. In December 2008, EnCana notified us that EnCana was exercising its right to become the operator of record for joint interest wells in North Bald Prairie under the carry and earning agreement. Either party may propose wells under the joint operating agreement between the parties.

Southwest Kentucky

Boomerang (New Albany Shale)

Our Boomerang prospect is a 74,988 gross (44,759 net) acre New Albany Shale play located in Southwest Kentucky in the Illinois Basin. We have a 60% working interest and a net revenue interest of approximately 50% in our Boomerang prospect. We recorded an impairment expense from a non-cash write-off of $2.3 million of drilling costs incurred for three test wells we drilled in 2007. We currently are formulating a development plan for this prospect.

Northeast British Columbia

Montney Tight Gas and Doig Shale

In August 2007, we acquired a non-operating, working interest ranging from 11.9% to 25% in a lease acquisition and drilling project targeting unconventional gas reserves in the emerging Montney tight gas and Doig Shale play in Northeast British Columbia. The project covers 31,231 gross (7,395 net) acres. The primary targets are Triassic-aged tight gas and shale gas. The Canadian operator has drilled three wells since the project began in August 2007, without commercial success. We have written off the carrying value of our minority equity investment in the Canadian operator by recognizing a non-cash write-off of $917,000. We also recorded an impairment expense from a non-cash write-off of $4.1 million, which represents our share of the drilling and completion costs related to our interest in the joint drilling project. We plan to continue to explore ways to recover our remaining carrying costs in this project, including potential development of shallower productive zones (such as the Doig Sand, North Pine, Halfway and Baldonnel) in addition to the primary targets, change of operator and the potential sale or farm-out of part or all of the parties' joint interest in the project.

Northern New Mexico

El Vado East (Mancos Shale)

Our El Vado East prospect is a 90,357 gross (79,793 net) acre Mancos Shale play located in the Chama Basin in Northern New Mexico in proximity to several productive fields, including the Puerto Chiquito West, Puerto Chiquito East and the Boulder fields, which collectively have produced in excess of 29 MMBoe of oil and gas. Our primary objective in El Vado East is the Mancos Shale at 2,000 to 3,000 feet. We have a 90% working interest and a net revenue interest of approximately 72% in our El Vado East prospect.

Since April 2008 our leasehold in Northern New Mexico has been the subject of regulatory proceedings and delays, including a moratorium on all drilling on private lands in Rio Arriba County, a proposed county drilling ordinance and potential state rulemaking. In light of these regulatory proceedings and continued expected delays in 2009, we currently have not allocated any capital to El Vado East for 2009.

Natural gas and oil reserves

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2008 and 2007. See Note 13 — Disclosures about Oil and Gas Producing Activities (unaudited) to our consolidated financial statements for additional information. Our estimated total proved reserves of natural gas and oil as of December 31, 2008 were 211.1 Bcfe. The 2008 reserves are composed of 82% natural gas and 18% oil, condensate and NGLs. The proved developed portion of total proved reserves at year end 2008 was 48%. Our reserve estimates and PV-10 (defined below) for the years ended December 31, 2008 and 2007 are based on an independent engineering study of our oil and gas properties prepared by DeGolyer and MacNaughton, our independent reserve engineers.

	Estimated Proved Reserves		
	Gas (MMcf)	Oil and NGLs (MBbls)	Total (MMcfe)
December 31, 2008			
Ozona Northeast			
Proved Developed	72,675	550	75,973
Proved Undeveloped	63,125	887	68,448
Total Proved	135,800	1,437	144,421
Cinco Terry			
Proved Developed	8,973	2,464	23,756
Proved Undeveloped	7,321	2,466	22,117
Total Proved	16,294	4,930	45,873
North Bald Prairie			
Proved Developed	2,569	—	2,569
Proved Undeveloped	18,205	—	18,205
Total Proved	20,774	—	20,774
Total			
Proved Developed	84,217	3,014	102,298
Proved Undeveloped	88,651	3,353	108,770
Total Proved	172,868	6,367	211,068
December 31, 2007			
Ozona Northeast			
Proved Developed	65,725	529	68,899
Proved Undeveloped	67,441	720	71,763
Total Proved	133,166	1,249	140,662
Cinco Terry			
Proved Developed	2,421	739	6,855
Proved Undeveloped	4,140	1,220	11,459
Total Proved	6,561	1,959	18,314
North Bald Prairie			
Proved Developed	2,105	—	2,105
Proved Undeveloped	19,319	—	19,319
Total Proved	21,424	—	21,424
Total			
Proved Developed	70,251	1,268	77,859
Proved Undeveloped	90,900	1,940	102,541
Total Proved	161,151	3,208	180,400

The standardized measure of discounted future net cash flows for our proved reserves at December 31, 2008 was $142.6 million.

The present value of our proved reserves, discounted at 10% (PV-10), was estimated at $221.1 million, based on year end weighted average prices of $6.04 per Mcf for natural gas, $39.60 per Bbl for oil and $23.00 per Bbl for NGLs. PV-10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. See "Reconciliation of non-GAAP financial measure (PV-10)" below for our definition of PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows.

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting,* updating its oil and gas reporting requirements, including reserve reporting. The new reporting requirements will be effective for our 2009 year-end proved reserve estimates. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 — Summary of Significant Accounting Policies for our discussion of the SEC's new oil and gas reporting requirements.

Reconciliation of non-GAAP financial measure (PV-10)

The following table shows our reconciliation of our PV-10 to our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with generally accepted accounting principles, or GAAP). 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. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis.

PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

	As of December 31, 2008
	(In thousands)
PV-10	$ 221,080
Less income taxes:	
Undiscounted future income taxes	(157,503)
10% discount factor	79,058
Future discounted income taxes	(78,445)
Standardized measure of discounted future net cash flows	$ 142,635

No estimates of our reserves have been filed with or included in reports to another federal authority or agency since year end.

Net production, unit prices and costs

The following table sets forth summary information regarding our production results, average sales prices and average production costs during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
Net production:			
Natural gas (MMcf)	7,092	4,801	6,282
Oil (MBbls)	175	72	77
Natural gas liquids (MBbls)	102	12	—
Total (MMcfe)	8,755	5,305	6,744
Average net daily production:			
Total (MMcfe)	24	15	18
Average realized sales price per unit (without the effects of commodity derivatives):			
Natural gas (per Mcf)	$ 8.29	$ 6.98	$ 6.66
Oil (per Bbl)	93.79	70.31	62.65
Natural gas liquids (per Bbl)	45.46	46.25	—
Average realized price (per Mcfe)	$ 9.12	$ 7.37	$ 6.92
Average realized sales price per unit (with the effects of commodity derivatives):			
Natural gas (per Mcf)	$ 8.71	$ 7.96	$ 7.65
Oil (per Bbl)	93.79	70.31	62.65
Natural gas liquids (per Bbl)	45.46	46.25	—
Average realized price (per Mcfe)	$ 9.46	$ 8.26	$ 7.84
Expenses (per Mcfe)			
Lease operating	$ 0.87	$ 0.72	$ 0.58
Severance and production taxes	0.48	0.31	0.26
Exploration	0.17	0.17	0.24
Impairment of non-producing properties	0.73	0.05	0.08
General and administrative	1.01	2.39	0.36
Depletion, depreciation and amortization	2.71	2.47	2.16

Productive wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest at December 31, 2008.

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	380.0	380.0	1.0	1.0	381.0	381.0
Cinco Terry	46.0	23.0	8.0	4.0	54.0	27.0
North Bald Prairie	10.0	5.0	0.0	0.0	10.0	5.0
Total Productive Wells	436.0	408.0	9.0	5.0	445.0	413.0

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2008.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	30,199	29,385	18,970	14,659	49,169	44,044
Cinco Terry	5,267	2,660	40,021	16,806	45,288	19,466
North Bald Prairie	3,481	1,701	5,820	2,660	9,301	4,361
Boomerang	—	—	74,988	44,759	74,988	44,759
Northeast British Columbia	3,896	561	27,335	6,834	31,231	7,395
El Vado East	—	—	90,357	79,793	90,357	79,793
Total	42,843	34,307	257,491	165,511	300,334	199,818

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2008 that will expire over the next three years by region unless production is established within the spacing or producing units covering the acreage prior to the expiration dates:

	2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	3,062	2,313	—	13	15,908	12,333
Cinco Terry	3,118	2,223	5,390	3,305	24,696	7,842
North Bald Prairie	3,174	2,098	2,646	562	—	—
Boomerang(1)	—	—	6,777	4,066	146	88
Northeast British Columbia	—	—	22,784	5,696	2,595	649
El Vado East(2)	90,357	79,793	—	—	—	—
Total	99,711	86,427	37,597	13,642	43,345	20,912

(1) Assumes the exercise of options to extend the current primary terms by three to five additional years (beginning July 2009 through December 2011) on 67,995 gross (40,565 net) acres. Options to extend 58,548 gross (35,027 net) acres have an exercise price of $2.00 per year per net acre for five total available years. Options to extend 7,510 gross (4,374 net) acres have an exercise price of $7 per year per net acre for five total available years. Options to extend the remaining 1,937 gross (1,164 net) acres have a weighted average exercise price of $38 per net acre for three to five total available years.

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

Drilling activity

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

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive(1)	83.0	54.5	51.0	46.0	81.0	53.3
Non-productive(2)	11.0	7.5	5.0	4.0	6.0	4.2
Exploratory wells:						
Productive	—	—	—	—	2.0	1.0
Non-productive(3)	2.0	0.5	1.0	0.7	—	—
Total wells:						
Productive	83.0	54.5	51.0	46.0	83.0	54.3
Non-productive	13.0	8.0	6.0	4.7	6.0	4.2

(1) Of the 83 gross productive wells drilled in 2008, 10 were waiting on completion at December 31, 2008.

(2) Of the 11 gross non-productive wells drilled in 2008, one well will be completed as a salt water disposal well in North Bald Prairie during the first half of 2009.

(3) The two gross exploratory wells drilled in 2008 were drilled by the Canadian operator of our Northeast British Columbia project.

Wells drilled in 2007 are pro forma for the November 14, 2007 acquisition of Neo Canyon Exploration, L.P.'s 30% working interest in Ozona Northeast, which we refer to as the Neo Canyon interest, as if the acquisition occurred on January 1, 2007.

Markets and customers

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

During the year ended December 31, 2008, Ozona Pipeline Energy Company, which we refer to as Ozona Pipeline, and WTG Benedum/Belvan Partners, LP, were our most significant purchasers, accounting for approximately 61.9% and 15.8%, respectively, of our total 2008 oil and gas sales excluding realized commodity derivative settlements.

Commodity derivative activity

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

All derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are currently recognized in the statement of operations unless specific commodity derivative accounting criteria are met. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) 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 (loss) 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 gain (loss) on commodity derivatives."

Title to properties

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

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

Competition

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

Regulation

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

Transportation and sale of gas

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

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

Regulation of production

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

Environmental regulations

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

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

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

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

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

Comprehensive Environmental Response, Compensation and Liability Act

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

Waste handling

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

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

Air emissions

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

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

Water discharges

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

OSHA and other laws and regulations

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

We believe that we are in substantial compliance with all existing environmental laws and regulations that apply to our current operations and that our ongoing compliance with existing requirements will not have a material adverse effect on our financial condition or results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2008. In addition, as of the date of this annual report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2009. However, the passage of more stringent laws or regulations in the future could have a negative effect on our business, financial condition and results of operations, including our ability to develop our undeveloped acreage. For example, see our discussion of current regulatory proceedings in New Mexico below.

New Mexico

In April 2008, the Board of County Commissioners of Rio Arriba County, New Mexico imposed a moratorium on all oil and gas drilling on private lands in Rio Arriba County, pending the adoption of an ordinance that would regulate oil and gas operations. The moratorium covers all of our El Vado East prospect in Rio Arriba County. In February 2009, the Board of Commissioners extended the moratorium through May 19, 2009.

In January 2009, the Board of Commissioners published a draft oil and gas drilling ordinance for the county. The draft ordinance is broad in its scope and application and would require submission of applications for a special use and development permits, along with a number of reports, plans, assessments and other supporting materials.

In addition to the county moratorium and proposed county regulations, in July 2008, the Governor of New Mexico directed the New Mexico Oil Conservation Division, or OCD, to propose special rules for oil and gas operations in Eastern Rio Arriba County, including our leasehold in El Vado East. Under the Governor's directive, these new rules would be proposed and adopted in a rulemaking proceeding through the New Mexico Oil Conservation Commission. The OCD recently has proposed special rules for portions of Santa Fe County and the Galisteo Basin that will materially increase the time and cost to conduct drilling operations in that area.

In light of the regulatory proceedings impacting our leasehold in Rio Arriba County, we currently have not allocated any capital to El Vado East for 2009. If adopted, the state and county rules and ordinances will increase the time and cost to explore for oil and gas in El Vado East and may render the project uneconomic for us.

In addition, ongoing delays in New Mexico affect our mineral lease for El Vado East. Our lease currently requires us to drill a minimum of eight wells before the primary term of the lease expires on April 2, 2009. The lease also provides that if our drilling operations are delayed or prevented as a result of a governmental or regulatory order or by failure to obtain permits, which are events of "force majeure," then our drilling commitment will be extended until 60 days after the cause of the delay is removed, as long as the primary term of the lease is not extended by more than four years. We have notified the lessor of the delays in El Vado East, which began in April 2008, and invoked the force majeure provision of the lease. Our inability to meet this drilling commitment, as extended by force majeure, or otherwise negotiate appropriate extensions under the lease, could result in the expiration of the lease and write-off of our investment in El Vado East, the current carrying value of which is $2.7 million.

Employees

At February 28, 2009, we had 36 full-time employees. 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* We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the charters of our Audit Committee and Compensation and Nominating Committee, and our Code of Conduct are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at One Ridgmar Centre, 6500 W. 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 Securities Exchange Act of 1934 (the "Exchange Act"). The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Approach, that file electronically with the SEC. The public can obtain any document we file with the SEC at *www.sec.gov*. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. *Risk Factors.*

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

Risks related to the oil and natural gas industry and our business

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

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

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

Further, oil prices and gas prices do not necessarily fluctuate in direct relationship to each other. Because more than 82% of our estimated proved reserves as of December 31, 2008 were gas reserves, our financial results are more sensitive to movements in gas prices. Recent gas prices have been extremely volatile and we expect this volatility to continue. For example, from January 1, 2008 to December 31, 2008, the NYMEX gas spot price ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu.

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

The deterioration of global economic and financial conditions and an extended decline in the price of oil and natural gas would negatively impact our business, financial condition and results of operations.

The global economic and financial crisis could lead to an extended national or global economic recession. The slowdown in economic activity caused by the current recession will likely reduce national and worldwide demand for oil and natural gas and result in lower commodity prices. Substantial decreases in oil and natural gas prices could have a material adverse effect on our business, financial condition and results of operations, limit our access to liquidity and credit and hinder our ability to fund our development program. The inability to execute our development program could also lead to low production and reserve growth.

If credit and capital markets do not improve, we may not be able to obtain funding under our current revolving credit facility or fund on acceptable terms. The inability to obtain funding could deter or prevent us from meeting our future capital needs to fund our development program.

Capital and credit markets have experienced unprecedented volatility and disruption and continue to be unpredictable. Given the current levels of market volatility and disruption, the availability of funds from those markets has diminished substantially. Further, arising from concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of accessing the credit markets has increased as many lenders have raised interest rates, enacted tighter lending standards or altogether ceased to provide funding to borrowers. Additionally, even if lenders are able to provide funding to borrowers, interest rates may rise in the future and therefore increase the cost of outstanding borrowings that we may incur under our revolving credit facility.

Moreover, we may be unable to obtain adequate funding under our current revolving credit facility. First, our lenders may be unwilling or unable to meet their funding commitments. Second, our borrowing base under our current revolving credit facility is redetermined semiannually. Our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors. If oil and gas prices significantly decline for an extended period of time, our lenders could redetermine the borrowing base by evaluating our reserves at substantially lower oil and gas prices. Such determination could result in a negative revision to our proved reserve value and reduce our borrowing base.

Due to these capital and credit market conditions, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to post collateral to support our obligations, or we may be unable to implement our development program, grow our existing business through acquisitions or joint ventures or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our business, financial condition and results of operations.

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

At December 31, 2008, we had approximately $43.5 million of outstanding debt under our revolving credit facility, and our borrowing base was $100.0 million. The borrowing base limitation under our credit facility is semi-annually redetermined based upon a number of factors, including commodity prices and reserve levels. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any twelve-month period. Upon a redetermination, our borrowing base could be substantially reduced, and in the event 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 utilize cash flow from operations and bank borrowings to fund our exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

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

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

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

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

Currently, all of our producing properties are located in four counties in Texas, and our proved reserves are primarily attributable to three fields, making us vulnerable to risks associated with having our production concentrated in a small area.

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

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

As of December 31, 2008, we held mineral leases 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 2009 and 2015. Options covering approximately 3,118 gross acres in our Cinco Terry project are scheduled to expire during 2009. If these leases or options expire, we will lose our right to develop the related properties. See Items 1. and 2. "Business and Properties — Acreage" for a table summarizing the expiration schedule of our undeveloped acreage over the next three years.

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

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

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

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

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

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

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

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

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

- the quantities of oil and gas that are ultimately recovered,
- the production and operating costs incurred,
- the amount and timing of future development expenditures, and
- future oil and gas prices.

As of December 31, 2008, approximately 52% 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. As required by the SEC, PV-10 is generally based on prices and costs as of the date of the measurement (December 31, 2008), while actual future prices and costs may be materially higher or lower. If gas prices decline by $1.00 per Mcf from $6.04 per Mcf to $5.04 per Mcf, then our PV-10 as of December 31, 2008 would decrease from $221.1 million to $163.2 million. The average market price received for our natural gas production for the month of December 31, 2008, after basis and Btu adjustments, was $6.02 per Mcf.

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

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

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

Our industry is cyclical, and from time to time there is a shortage of drilling rigs, equipment, supplies and qualified personnel. Although commodity prices weakened considerably in the second half of 2008, creating more availability of rigs, equipment and personnel, during periods of strong commodity prices, the costs and delivery times of rigs, equipment and supplies are substantially greater. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected.

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

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

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

In 2008, Ozona Pipeline and WTG Benedum/Belvan Partners, LP accounted for approximately 61.9% and 15.8%, respectively, of our total oil and gas sales excluding realized commodity derivative settlements. To the extent that Ozona Pipeline or WTG Benedum/Belvan Partners reduces their purchases in gas or oil or defaults on their obligations to us, we would be adversely affected unless we were able to make comparably favorable arrangements with other customers. These purchasers' default or non-performance could be caused by factors beyond our control. A default could occur as a result of circumstances relating directly to one or both of these customers, or due to circumstances related to other market participants with which the customer has a direct or indirect relationship.

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

Our success largely depends on the skills, experience and efforts of our management team and other key personnel. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial condition, results of operations and future growth. We have entered into employment agreements with J. Ross Craft, our President and Chief Executive Officer, Steven P. Smart, our Executive Vice President and Chief Financial Officer and Glenn W. Reed, our Executive Vice President — Engineering and Operations. 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.

We have three affiliated stockholders who, together with our board and management, have a 42.5% interest in our company, whose interests may differ from your interests and who will be able to control or substantially influence the outcome of matters voted upon by our stockholders.

At December 31, 2008, Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P. and Yorktown Energy Partners VII, L.P., or collectively, Yorktown, which are under common management, beneficially owned approximately 32.5% of our outstanding common stock in the aggregate, together with a Yorktown representative who serves on our board of directors. In addition, our non-Yorktown directors and management team beneficially own or control approximately 10.0% of our common stock outstanding. As a result of this ownership and control, Yorktown, together with our board and management, has the ability to control or substantially influence the vote in any election of directors. Yorktown, together with our board and management, also has control or substantial influence over our decisions to enter into significant corporate transactions and, in their capacity as our majority stockholders, these stockholders may have the ability to effectively block any transactions that they do not believe are in Yorktown's or management's best interest. As a result, Yorktown, together with our board and management, is able to control, directly or indirectly and subject to applicable law, or substantially influence all matters affecting us, including the following:

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

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

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

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

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

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

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

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

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

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

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

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

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

Under current federal tax laws, we are entitled to certain deductions relating to our operations, including deductions for intangible drilling costs, or IDCs, and depletion deductions. The President's budget for the fiscal year 2010 outlines proposals to eliminate several oil and gas federal income tax incentives, including deductions for IDCs and percentage depletion allowance for oil and natural gas. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could adversely our results of operations and cash flows.

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

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

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

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

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

Our results are subject to quarterly and seasonal fluctuations.

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

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

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

Market conditions and the unavailability of satisfactory oil and gas processing and transportation may hinder our access to oil and gas markets or delay our production. Although currently we control the gathering system operations for a majority of our production in the Ozona Northeast field, we do not have such control over the regional or downstream pipelines in Ozona Northeast or in other areas where we operate or expect to conduct operations. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In addition, the amount of oil and gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases we are provided with limited, if any, notice as to when these circumstances will arise and their duration. As a result, we may not be able to sell, or may have to transport by more expensive means, the oil and gas production from wells or we may be required to shut in gas wells or delay initial production until the necessary gathering and transportation systems are available. For example, in 2008 we reported that production in Ozona Northeast was shut-in and curtailed due to the impact of Hurricane Ike on downstream natural gas processing facilities and, separately, the rupture of a third-party pipeline. Any significant curtailment in gathering system or pipeline capacity, or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition or results of operations.

Environmental liabilities may expose us to significant costs and liabilities.

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

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

Our growth strategy may include acquiring oil and gas businesses and properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully.

Furthermore, acquisitions involve a number of risks and challenges, including:

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

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

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

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

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

A terrorist attack or armed conflict could harm our business.

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

Risks related to our financial condition

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

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flows, borrowings under our revolving credit facility and issuances of common stock. We also require capital to fund our exploration and development budget. As of December 31, 2008, approximately 52% of our total estimated proved reserves were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We will be required to meet our needs from our internally generated cash flows, debt financings and equity financings.

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

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

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

At December 31, 2008, we had $43.5 million in outstanding borrowings under our revolving credit facility. At February 28, 2009, we had $47.4 million in long-term debt outstanding under our revolving credit facility. The borrowing base limitation under our revolving credit facility is redetermined semi-annually.

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

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

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

To manage our exposure to price risks in the marketing of our oil and gas production, we enter into oil and gas price commodity derivative agreements. While intended to reduce the effects of volatile oil and gas prices, such transactions may limit our potential gains and increase our potential losses if oil and gas prices were to rise substantially over the price established by the commodity derivative. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative arrangement or the counterparties to the commodity derivative agreements fail to perform under the contracts.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

We are involved in various legal and regulatory proceedings arising in the normal course of business. We do not believe that an adverse result in any pending legal or regulatory proceeding, together or in the aggregate, would be material to our business, financial condition or results of operations.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

None.

PART II

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

Trading market and range of common stock

Our common stock is traded on the NASDAQ Global Select Market, or Nasdaq, in the United States under the symbol "AREX." During 2008, trading volume averaged 134,407 shares per day. The following table shows the quarterly high and low sale prices of our common stock as reported on Nasdaq since our initial public offering on November 8, 2007, which refer to as the IPO.

	High	Low
2007		
Fourth quarter (November 8 — December 31)(1)	$13.64	$11.68
2008		
First quarter	$16.90	$ 9.20
Second quarter	28.87	15.17
Third quarter	30.00	9.92
Fourth quarter	14.25	5.39

(1) Our common stock began trading on Nasdaq on November 8, 2007.

Holders of record

As of February 28, 2009, there were 27 record holders of our common stock. In many instances, a registered stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

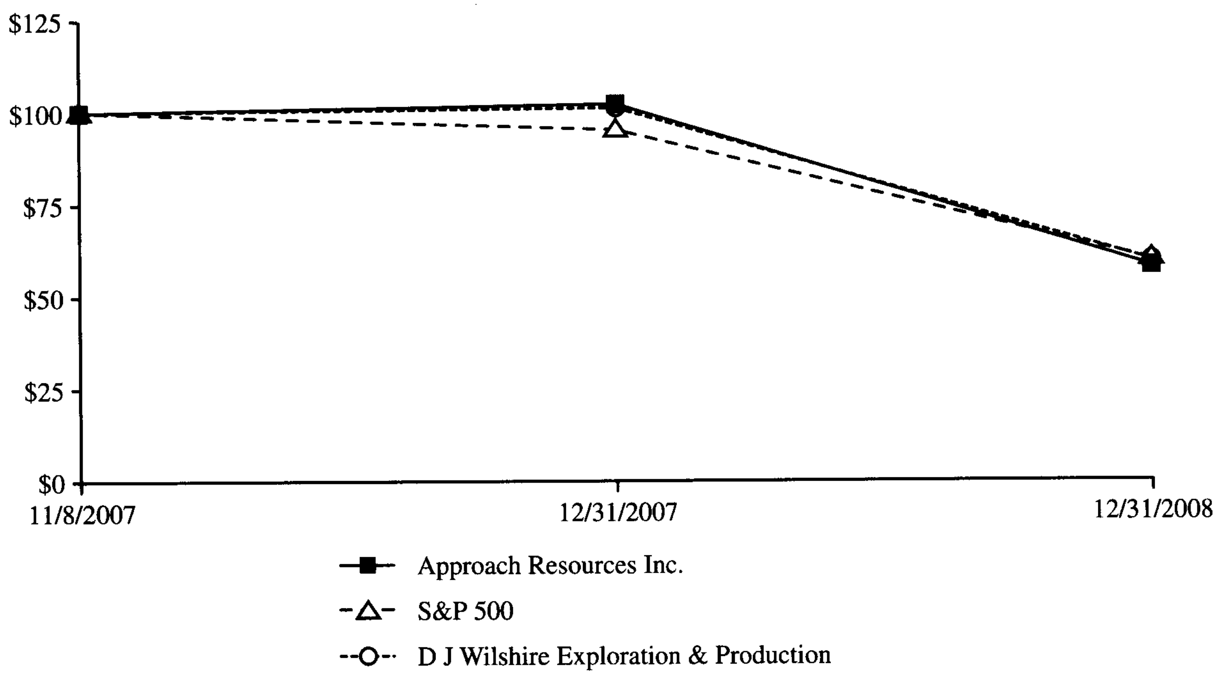
Dividends

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.

Comparison of cumulative return

The following graph compares the cumulative return on a $100 investment in our common stock from November 8, 2007, through December 31, 2008, to that of the cumulative return on a $100 investment in the Standard & Poor's 500 Index and the Dow Jones Wilshire Exploration & Production 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 of 1933, which we refer to as the Securities Act, or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

Comparison of Total Return from November 8, 2007 through December 31, 2008
Among Approach Resources Inc., the Standard & Poor's 500 Index and
the Dow Jones Wilshire Exploration & Production Index



	11/8/2007	12/31/2007	12/31/2008
Approach Resources Inc.	$100.00	$102.14	$58.06
S&P 500	100.00	95.15	59.95
D J Wilshire Exploration & Production	100.00	101.09	59.62

Recent sales of unregistered securities

We did not sell any securities during the year ended December 31, 2008 that were not registered under the Securities Act.

Issuer repurchases of equity securities

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 of Shares That May Yet be Purchased Under the Plans or Programs
October 1, 2008 — October 31, 2008	0	N/A	0	See Note
November 1, 2008 — November 30, 2008	5,621	$9.60	5,621	See Note
December 1, 2008 — December 31, 2008	0	N/A	0	See Note
Total	5,621	$9.60	5,621	See Note

Note: We adopted the Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 and amended it effective December 31, 2008. The 2007 Stock Incentive Plan allows us to withhold shares of common stock to pay withholding taxes payable upon vesting of a restricted stock grant. The number of shares of common stock available for grants under the 2007 Stock Incentive Plan is increased by the number of shares withheld as payment of such withholding taxes. On November 14, 2008, we withheld 5,621 shares of common stock as the market closing price of $9.60 per share to satisfy the income tax withholding obligations arising upon the vesting of 21,250 restricted shares issued to an executive officer in March 2007 under the 2007 Stock Incentive Plan.

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, 2008.

Plan Category:	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by stockholders	434,302	$8.47	1,461,016
Equity compensation plans not approved by stockholders	—	—	—

Item 6. *Selected Financial Data.*

The following table sets forth selected financial information for the five years ended December 31, 2008. All weighted average shares and per share data have been adjusted for the three-for-one stock split, and the stock issuance resulting from the combination of Approach Oil & Gas Inc., or AOG, under a contribution agreement effective November 14, 2007. This information should be read in conjunction with Item 7 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements, related notes and other financial information included in this report.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Operating results data					
Revenues:					
Oil and gas sales	$ 79,869	$ 39,114	$ 46,672	$ 43,264	$ 5,682
Expenses:					
Lease operating	7,621	3,815	3,889	2,910	179
Severance and production taxes	4,202	1,659	1,736	1,975	407
Exploration	1,478	883	1,640	733	2,396
Impairment of non-producing properties	6,379	267	558	—	—
General and administrative	8,881	12,667	2,416	2,659	1,943
Depletion, depreciation and amortization	23,710	13,098	14,551	8,011	1,224
Total expenses	52,271	32,389	24,790	16,288	6,149
Operating income (loss)	27,598	6,725	21,882	26,976	(467)
Other:					
Impairment of investment	(917)	—	—	—	—
Interest (expense) income, net	(1,269)	(5,219)	(3,814)	(802)	201
Realized gain (loss) on commodity derivatives	2,936	4,732	6,222	(2,925)	—
Change in fair value of commodity derivatives	7,149	(3,637)	8,668	(4,163)	—
Income (loss) before provision (benefit) for income taxes	35,497	2,601	32,958	19,086	(266)
Provision (benefit) for income taxes	12,111	(108)	11,756	7,028	—
Net income (loss)	$ 23,386	$ 2,709	$ 21,202	$ 12,058	$ (266)
Earnings (loss) per share:					
Basic	$ 1.13	$ 0.25	$ 2.26	$ 1.32	$ (0.05)
Diluted	$ 1.12	$ 0.24	$ 2.20	$ 1.32	$ (0.05)
Statement of cash flows data					
Net cash provided (used) by:					
Operating activities	$ 56,435	$ 30,746	$ 34,305	$ 40,588	$ 4,528
Investing activities	(100,633)	(52,940)	(59,384)	(72,224)	(26,859)
Financing activities	43,696	22,062	26,771	32,199	22,474
Effect of Canadian exchange rate	(206)	6	—	—	—
Balance sheet data					
Cash and cash equivalents	$ 4,077	$ 4,785	$ 4,911	$ 3,219	$ 2,656
Other current assets	30,760	12,021	12,792	15,701	5,939
Property, equipment, net, successful efforts method	303,404	230,819	132,520	89,407	24,742
Other assets	—	1,101	86	89	1,565
Total assets	$ 338,241	$248,726	$150,309	$108,416	$ 34,902
Current liabilities	$ 30,775	$ 22,017	$ 15,421	$ 32,746	$ 9,827
Long-term debt	43,537	—	47,619	29,425	100
Other long-term debt liabilities	40,116	26,890	17,697	6,555	99
Stockholders' equity	223,813	199,819	69,572	39,690	24,876
Total liabilities and stockholders' equity	$ 338,241	$248,726	$150,309	$108,416	$ 34,902

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

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

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of unconventional natural gas and oil properties in the United States and British Columbia. We focus on tight gas sands and shale and have assembled leasehold interests aggregating approximately 300,334 gross (199,818 net) acres as of December 31, 2008. We expect to leverage our management team's proven track record of finding and exploiting unconventional reservoirs through advanced completion, fracturing and drilling techniques. As the operator of over 90% of our production and proved reserves, we have a high degree of control over capital expenditures and other operating matters.

We currently operate or have interests in the following areas:

West Texas

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

East Texas

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

Southwest Kentucky

- Boomerang (New Albany Shale)

Northeast British Columbia

- Montney tight gas and Doig Shale

Northern New Mexico

- El Vado East (Mancos Shale)

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.

At December 31, 2008, we owned working interests in 445 producing oil and gas wells, had estimated proved reserves of approximately 211.1 Bcfe and were producing 28.0 MMcfe/d (based on production for the month of December 2008). Our average daily net production for 2009 (through February) was 26.5 MMcfe/d.

As of December 31, 2008, all of our proved reserves and production were located in Ozona Northeast and Cinco Terry in West Texas and in North Bald Prairie in East Texas. At year end 2008, our proved reserves were 82% natural gas, 48% proved developed and had a reserve life index of over twenty years (based on 2008 production of 8,755 MMcfe). In addition to our producing wells, we had identified 1,205 total drilling locations in Ozona Northeast, Cinco Terry and North Bald Prairie at December 31, 2008, of which 312 are proved.

Our financial results depend upon many factors, particularly the price of oil and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, estimates of inventory storage levels, gas price differentials and other factors. A factor potentially impacting the future supply balance is the recent increase in the United States LNG import capacity. Significant LNG capacity increases have been announced that may result in increased price volatility. 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 the capital market.

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. Our future growth will depend upon our ability to continue to add oil and gas reserves in excess of production at a reasonable cost. We will maintain our focus on the costs of adding reserves through drilling and acquisitions as well as the costs necessary to produce such reserves.

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

Reduction in capital expenditures and drilling activities

In December 2008, in response to a decline in oil, gas and NGL prices and uncertain market conditions, we announced that we were reducing our capital expenditure budget to $43.8 million in 2009, compared to $100.1 million of actual capital expenditures in 2008 (including $10.3 million in exploration and development costs related to the acquisition of deep rights in Ozona Northeast in July 2008). We also have reduced the number of our operating rigs from five in June 2008 to two at February 28, 2009. We intend to fund 2009 capital expenditures (excluding any acquisitions) with internally-generated cash flow, with any excess cash flow applied towards debt, working capital or strategic acquisitions. We will continue to monitor commodity prices and operating expenses to determine any further adjustments to the capital budget and, unless commodity prices strengthen, we will materially reduce our 2009 capital expenditures and number of operated rigs. The previously-announced reduction in capital expenditures and drilling activities, along with any additional reductions undertaken by the Company, could materially reduce our production volumes and revenues from pre-2009 levels and increase future expected costs necessary to develop existing reserves.

Critical accounting policies and estimates

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

Oil and gas activities — successful efforts

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

- geological and geophysical evaluation costs are expensed as incurred,
- dry holes for exploratory wells are expensed, and dry holes for developmental wells are capitalized, and
- Capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with 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 unproved properties and their estimated fair values based on the present value of the related future net cash flows. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2008, 2007 or 2006.

Our engineering 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 the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. 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 as a result of changing results from operational activity and results. Changes in commodity prices, operation costs and techniques may also affect the overall evaluation of reservoirs. A hypothetical 10% decline in our December 31, 2008 proved reserves volumes would have been insignificant to depletion expense for the year ended December 31, 2008 nor would it have resulted in an impairment of oil and gas properties.

Our estimated proved reserves as of December 31, 2008, 2007 and 2006 were prepared by DeGolyer and MacNaughton.

Derivative instruments and commodity derivative activities

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

We are exposed to credit losses in the event of nonperformance by the counterparty on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparty 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. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) 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 (loss) 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 year ended December 31, 2008, we recognized an unrealized gain of $7.1 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2007, we recognized an unrealized loss of $3.6 million from the change in the fair value of commodity derivatives. A 10% increase in the NYMEX floating prices would have resulted in a $1.7 million decrease in the December 31, 2008 fair value recorded on our balance sheet, and a corresponding decrease to the gain on commodity derivatives in our statement of operations.

Asset retirement obligation

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

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

Share-based compensation

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

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the years ended December 31, 2008 and 2007. There were no options granted during the year ended December 31, 2006.

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

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

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

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

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

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

A 10% or 20% increase in the volatility, risk-free interest rate or stock price would not have significantly impacted share-based compensation expense for the year ended December 31, 2008.

Recent accounting pronouncements

In March 2008, the Financial Accounting Standards Board, or FASB, issued Statement of Financial Accounting Standard 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement 133, or SFAS 161. SFAS 161 amends and expands the disclosure requirements of FASB Statement 133 with the intent to provide users of financial statement with an enhanced understanding of (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and the related hedged items are accounted for under FASB Statement 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect and entity's financial position, financial performance and cash flows. SFAS 161 is effective for financial statements issued for years and interim periods beginning after November 15, 2008. The effect of adopting SFAS 161 is not expected to have a significant effect on our reported financial position or earnings.

In December 2007, FASB issued Statement of Financial Accounting Standards 141 (revised 2007), *Business Combinations*, or SFAS 141(R). SFAS 141(R), among other things, establishes principles and requirements for how the acquirer in a business combination (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquired business, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning on or after December 15, 2008, with early adoption prohibited. This standard will change our accounting treatment for business combinations on a prospective basis.

In December 2007, the FASB issued Statement of Financial Accounting Standards 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51*, or SFAS 160. SFAS 160 establishes accounting and reporting standards for noncontrolling interests in a subsidiary and for the deconsolidation of a subsidiary. Minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. It also establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary and requires expanded disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008, with early adoption prohibited. The effect of adopting SFAS 160 is not expected to have a significant effect on our reported financial position or earnings.

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, 2008, 2007 or 2006. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the cost of labor or supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher prices.

Share-based compensation

Our 2007 Stock Incentive Plan allows grants of stock and options to employees and outside directors. Granting of awards may increase our general and administrative expenses subject to the size and timing of the grants. See Note 6 to our consolidated financial statements.

Recent developments in reserve reporting

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting*, updating its oil and gas reporting requirements. The new reporting requirements will be effective for our financial statements for the year ending December 31, 2009 and our 2009 year-end proved reserve estimates. The new reporting requirements include provisions that:

- Permit the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes,
- Allow companies to disclose their probable and possible reserves in SEC-filed documents (currently, SEC rules limit disclosure to only proved reserves),
- Require companies to report the independence and qualifications of a reserves preparer or auditor,
- Require companies to file a report when a third party is relied upon to prepare reserves estimates or conducts a reserves audit, and
- Require companies to report oil and gas reserves using an average price based upon the prior 12-month period (rather than year-end prices).

We are currently evaluating the impact that these new reporting requirements will have for the year ended December 31, 2009.

Results of operations

Years ended December 31, 2008 and 2007

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

Oil and gas sales. Oil and gas sales increased $40.8 million, or 104.2%, for the year ended December 31, 2008 to $79.9 million from $39.1 million for the year ended December 31, 2007. The increase in oil and gas sales principally resulted from our increased ownership in the Ozona Northeast field as a result of our acquisition of the Neo Canyon interest in the fourth quarter of 2007 and increased revenue from our Cinco Terry and North Bald Prairie fields. We now own substantially all of the working interest in Ozona Northeast. Of the 8,755 MMcfe of production reported for 2008, approximately 1,791 MMcfe was attributable to the interest acquired from Neo Canyon. The increase in oil and gas sales also resulted from continued development of our Cinco Terry and North Bald Prairie fields. Cinco Terry production increased by 2,097 MMcfe compared to the prior year. Production from North Bald Prairie accounted for 447 MMcfe in production for 2008. Further, the average price per Mcfe we received for our production increased from $7.37 to $9.12 per Mcfe as average oil and gas prices increased significantly between the two years. Of the $40.8 million increase in revenues, $32.8 million was attributable to growth in volume with the remaining $8.0 million due to oil and gas price increases. Natural gas sales represented 73.6% of the total oil and gas sales in 2008 compared to 85.6% in 2007, as our Cinco Terry field has a larger component of oil and NGLs in its production.

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

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

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

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

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

Impairment of oil and gas properties. In accordance with SFAS 144, we review our long-lived assets to be held and used, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets, we recorded an impairment of oil and gas properties of $6.4 million and $267,000 in 2008 and 2007, respectively. The 2008 impairment resulted from a non-cash write-off of $2.3 million of drilling costs incurred for three test wells in our Boomerang project and $4.1 related to the drilling and completion of three wells in our Northeast British Columbia project. The 2007 impairment resulted from the abandonment of an expiring leasehold position in Ozona Northeast covering 2,282 acres.

General and administrative. Our general and administrative expenses decreased $3.8 million, or 29.9%, to $8.9 million ($1.01 per Mcfe) for the year ended December 31, 2008 from $12.7 million ($2.39 per Mcfe) for the year ended December 31, 2007. General and administrative expenses for 2007 included $4.6 million in non-cash, share-based compensation (of which $3.9 million was related to the IPO), $2.4 million in cash incentive compensation to cover out-of-pocket taxes related to IPO stock awards, $1.0 million of cash incentive compensation related to the IPO and $0.7 million in cash incentive compensation to cover out-of-pocket taxes related to management's exchange of common stock in 2007 to repay full recourse management notes before the IPO. Partially offsetting the higher expenses in 2007 was an increase in general and administrative expense in 2008 attributable to increased salaries and benefits of $2.0 million related to an increase in staff, professional fees of $900,000, share-based compensation of $1.1 million and cash incentive compensation of $967,000. Additionally, the 2007 period includes a severance obligation of $350,000 related to a former employee. Following is a summary of general and administrative expenses (in millions and per Mcfe):

	2008		2007		Change		%
	$MM	Mcfe	$MM	Mcfe	$MM	Mcfe	Change
Salaries and benefits	$4.8	$0.55	$ 2.8	$0.54	$ 2.0	$ 0.01	1.8%
Professional fees	1.4	0.16	0.5	0.10	0.9	0.06	60.0
Share-based compensation	1.1	0.13	4.6	0.87	(3.5)	(0.74)	(85.1)
Cash incentive compensation	1.0	0.11	4.1	0.77	(3.1)	(0.66)	(85.7)
Other	0.6	0.06	0.7	0.11	(0.1)	(0.05)	(45.5)
Total	$8.9	$1.01	$12.7	$2.39	$(3.8)	$(1.38)	(57.7)%

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

Interest expense, net. Our interest expense decreased $4.0 million, or 75.7%, to $1.3 million for the year ended December 31, 2008 from $5.2 million for the year ended December 31, 2007. This decrease was substantially the result of our lower average debt level and lower interest rates in 2008. Additionally, interest expense for the year ended December 31, 2007 included $1.5 million related to the beneficial conversion feature of our convertible notes and $548,000 relating to accrued interest on the convertible notes.

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

Years ended December 31, 2007 and 2006

	Year Ended December 31, 2007	Year Ended December 31, 2006
Revenues (in thousands):		
Gas	$33,497	$41,851
Oil	5,617	4,821
Total oil and gas sales	$39,114	$46,672
Realized gain on commodity derivatives	4,732	6,222
Total oil and gas sales including derivative impact	43,846	52,894
Production:		
Gas (MMcf)	4,801	6,282
Oil (MBbls)	84	77
Total (MMcfe)	5,305	6,744
Average prices:		
Gas (per Mcf)	$ 6.98	$ 6.66
Oil (per Bbl)	66.87	62.65
Total (per Mcfe)	$ 7.37	$ 6.92
Realized gain on commodity derivatives (per Mcfe)	0.89	0.92
Total per Mcfe including derivative impact	$ 8.26	$ 7.84
Costs and expenses (per Mcfe):		
Lease operating	$ 0.72	$ 0.58
Severance and production taxes	0.31	0.26
Exploration	0.17	0.24
Impairment of non-producing properties	0.05	0.08
General and administrative	2.39	0.36
Depletion, depreciation and amortization	2.47	2.16

Oil and gas sales. Oil and gas sales decreased $7.6 million, or 16.2%, for the year ended December 31, 2007 to $39.1 million from $46.7 million for the year ended December 31, 2006. The decrease in sales principally resulted from a 21.3% decrease in production, as we drilled and completed 51 gross (46 net) wells in 2007 compared to the 81 gross (53.3 net) wells drilled and completed in 2006. The effects of decreased production were partially offset by an increase in price. The average price before the effect of commodity derivatives increased $0.45 per Mcfe, or 6.5%, from $6.92 per Mcfe in 2006 to $7.37 per Mcfe in 2007. Gas sales represented 85.6% of the total oil and gas sales in 2007 compared to 89.7% in 2006.

Commodity derivative activities. Realized gains from our commodity derivative activity increased our earnings $4.7 million and $6.2 million for the years ended December 31, 2007 and 2006, respectively. The change in fair value of commodity derivatives was a $3.6 million decrease for the year ended December 31, 2007 and an $8.7 million increase for the year ended December 31, 2006. During the years ended December 31, 2007 and 2006, we used gas swaps to mitigate commodity price risk. The general improvement in underlying commodity prices caused the decrease in realized gains in 2007 compared to 2006. During 2007 and 2006, commodity prices tended to be lower than the notional prices specified in our swap agreements, which resulted in a gain to us. Additionally, we entered into a mix of swaps and collars in 2007, which resulted in less volatility to the results of operations.

Lease operating expense. Our lease operating expenses, or LOE, decreased $74,000, or 1.9%, for the year ended December 31, 2007 to $3.8 million from $3.9 million for the year ended December 31, 2006. The primary factor in the slight decrease in LOE was the release in mid-2006 of one of our seven rented compressors and an amine unit, which was partially offset by higher ad valorem taxes in the year ended December 31, 2007.

Severance and production taxes. Our production taxes decreased $77,000, or 4.4%, for the year ended December 31, 2007 to $1.7 million from $1.7 million for the year ended December 31, 2006. The decrease in production taxes is a function of decreased oil and gas revenues that were more than offset by refunds received in 2006 applicable to prior years. Severance and production taxes were 4.2% and 3.7% as a percentage of oil and gas sales for the years ended December 31, 2007 and December 31, 2006, respectively. Our natural gas production from the Ozona Northeast field is afforded a severance tax rate lower than the normal rate (7.5%). However, we are required to file abatement requests with the State of Texas to receive the lower rate. Until the abatement requests are approved, we are required to pay the normal rate.

Exploration and impairment of non-producing properties. Our exploration costs decreased $757,000 to $883,000 for the year ended December 31, 2007 from $1.6 million for the year ended December 31, 2006. The 2007 period included dry hole costs of $623,000 from a well in our Boomerang prospect and $263,000 from a well in our Cinco Terry project. The 2006 period included dry hole costs of $1.3 million related to two wells drilled on a prospect in Pecos County, Texas, $195,000 from one well in Ozona Northeast and $165,000 from a well in our Boomerang prospect.

Our impairment of non-producing properties of $267,000 and $558,000 in 2007 and 2006, respectively, arose from the abandonment of a leasehold position in Ozona Northeast in 2007 and the abandonment of our leasehold position in Pecos County in 2006. As a result of the abandonment in Pecos County, we no longer anticipate incurring any future costs related to these leaseholds.

General and administrative. Our general and administrative expenses increased $10.3 million, or 424.3%, to $12.7 million for the year ended December 31, 2007 from $2.4 million for the year ended December 31, 2006. General and administrative expenses for 2007 included $4.6 million in non-cash, share-based compensation (of which $3.9 million was related to the IPO), $2.4 million in cash incentive compensation to cover out-of-pocket taxes related to IPO stock awards, $1.0 million of cash incentive compensation related to the IPO and $0.7 million in cash incentive compensation to cover out-of-pocket taxes related to management's exchange of common stock in 2007 to repay full recourse management notes before the IPO. General and administrative expenses for 2007 also increased over the prior year as a result of higher professional, staffing and public company expenses.

Depletion, depreciation and amortization, or DD&A. Our DD&A expense decreased $1.5 million, or 10.0% to $13.1 million for the year ended December 31, 2007 from $14.6 million for the year ended December 31, 2006. This decrease was primarily attributable to decreased production partially offset by increased oil and gas property costs in 2007. Our DD&A expense per Mcfe produced increased by $0.31, or 14.4%, to $2.47 per Mcfe for the year ended December 31, 2007, as compared to $2.16 per Mcfe for the year ended December 31, 2006.

Interest expense, net. Our interest expense increased $1.4 million, or 36.8%, to $5.2 million for the year ended December 31, 2007 from $3.8 million for the year ended December 31, 2006. Included in interest expense for the year ended December 31, 2007 were $1.5 million related to the beneficial conversion feature of our convertible notes and $548,000 relating to accrued interest on the convertible notes. Additionally, we had increased borrowings between the two periods to fund our development of the Ozona Northeast field. These increases in interest expense were partially offset by lower interest rates in the 2007 period.

Income taxes. Income taxes decreased $11.9 million, or 100.9%, to a benefit of $108,000 for the year ended December 31, 2007 from a provision of $11.8 million for the year ended December 31, 2006. The effective tax rate was a benefit of 4.2% and an expense of 35.7% for the years ended December 31, 2007 and December 31, 2006, respectively. Income taxes decreased consistent with our income before tax and the realization of a $2.8 million tax benefit related to the release of a valuation allowance on net operating loss carryovers generated by AOG before the combination of AOG and Approach under the contribution agreement on November 14, 2007.

Liquidity and capital resources

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

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

We intend to fund 2009 capital expenditures (excluding any acquisitions) with internally generated cash flow, with any excess cash flow applied towards debt, working capital or strategic acquisitions. We will continue to monitor commodity prices and operating expenses to determine any further adjustments to the capital budget. Unless commodity prices strengthen, we will further reduce our expected 2009 capital expenditures from our previously-announced capital budget of $43.8 million, which reduction could be substantial. A further reduction in capital expenditures could materially reduce our production volumes and revenues from pre-2009 levels and increase future expected costs necessary to develop existing reserves.

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

Our primary sources of cash in 2007 were from financing and operating activities. Approximately $64.3 million from borrowings under our revolving credit facility, $72.4 million from the issuance of common stock, $20.0 million from proceeds from convertible notes and $30.7 million cash from operations were used to fund our drilling activities, repay our revolving credit facility and purchase 2,021,148 shares of our common stock from the selling stockholder in our IPO.

For the year ended December 31, 2006, our primary sources of cash were from financing and operating activities. Approximately $18.2 million from borrowings (net of payments) under our revolving credit facility, $6.5 million from the issuance of common stock, $3.5 million from a loan from one of our stockholders and $34.3 cash from operations were used to fund our $59.4 million drilling program, the acquisition of another working interest in the Ozona Northeast field and $1.3 million to repurchase shares and cancel stock options.

Our cash flow from operations is driven by commodity prices and production volumes. Prices for oil and gas are driven by seasonal influences of weather, national and international economic and political environments and, increasingly, from heightened demand for hydrocarbons from emerging nations, particularly China and India. Our working capital is significantly influenced by changes in commodity prices and significant declines in prices could decrease our exploration and development expenditures. Cash flows from operations were primarily used to fund exploration and development of our mineral interests. In comparing 2008 and 2007, our cash flows from operations increased in 2008 due mostly to higher oil and gas sales partially offset by an increase in most operating expense categories and a decrease in working capital components during the year ended December 31, 2008. In comparing 2007 and 2006, our cash flows from operations decreased in

2007 due mostly to lower oil and gas sales and higher general and administrative expenses during the year ended December 31, 2007.

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

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flows provided by operating activities	$ 56,435	$ 30,746	$ 34,305
Cash flows used in investing activities	(100,633)	(52,940)	(59,384)
Cash flows provided by financing activities	43,696	22,062	26,771
Effect of Canadian exchange rate	(206)	6	—
Net (decrease) increase in cash and cash equivalents	$ (708)	$ (126)	$ 1,692

Operating activities

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

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

Investing activities

The majority of our cash flows used in investing activities for the years ended 2008, 2007 and 2006 have been used for the continued development of the Ozona Northeast, Cinco Terry and North Bald Prairie fields. The following is a summary of capital expenditures by prospect (in thousands):

	2008	2007	2006
Exploration and development costs:			
Ozona Northeast	$ 31,362	$27,986	$52,303
Ozona Northeast deep rights acquisition	10,346	—	—
Cinco Terry	32,363	10,586	3,176
North Bald Prairie	15,871	4,974	—
El Vado East	176	—	—
Boomerang	290	2,496	—
Inventory	2,365	—	—
Northeast British Columbia	2,993	1,235	—
Lease acquisition, geological, geophysical and other(1)	4,323	4,920	3,873
Totals	$100,089	$52,197	$59,352

(1) Includes $1.9 million of leasehold acquisitions related to Ozona Northeast and $2.0 million of leasehold acquisitions related to Cinco Terry during the year ended December 31, 2008. Includes $3.0 million for undeveloped leaseholds in our Northeast British Columbia prospect and $2.5 million for undeveloped leaseholds in our El Vado East prospect during the year ended December 31, 2007. Includes $3.5 million that was invested in undeveloped leaseholds in our Boomerang prospect for the year ended December 31, 2006.

In December 2008, we announced an exploratory and development budget of $43.8 million for 2009. We will materially reduce this budget unless commodity prices strengthen. Our budgets are established based on expected volumes to be produced and commodity prices.

Financing activities

We borrowed $121.7 million under our revolving credit facility in 2008 compared to $64.3 million in 2007. We repaid a total of $78.2 million and $111.9 million of amounts outstanding under our revolving credit facility for the years ended December 31, 2008 and 2007, respectively. Additionally, we borrowed $20 million in 2007 by issuing convertible notes. These notes were converted to outstanding shares of our common stock in connection with our IPO in November 2007. For 2006, we borrowed $119.5 million under our revolving credit facility, repaid $101.4 million under the facility and spent $1.3 million to purchase common stock and related options from a former employee.

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

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

In 2006, we borrowed $119.5 million under our revolving credit facility and repaid $101.4 million. Additionally in 2006, we sold approximately $6.5 million of common stock and spent $1.3 million to purchase common stock and related options from a former employee. These net proceeds were primarily used to fund a portion of our drilling program in Ozona Northeast and Cinco Terry and the acquisition of our Boomerang prospect.

Our goal is to actively manage our borrowings to help us maintain the flexibility to expand and invest, and to avoid the problems associated with highly leveraged companies of large interest costs and possible debt reductions restricting ongoing operations.

We believe that cash flow from operations will finance substantially all of our anticipated drilling, exploration and capital needs in 2009. We may use our revolving credit facility for possible acquisitions and temporary working capital needs. We also may determine to access the public equity or debt market for potential acquisitions, working capital or other liquidity needs, if such financing is available on acceptable terms. Given the current conditions of credit and capital markets, we cannot predict whether additional liquidity from debt or equity financings beyond our credit facility will be available on acceptable terms, or at all, in the foreseeable future.

Future capital expenditures for 2009

We intend to fund 2009 capital expenditures (excluding any acquisitions) with internally generated cash flow, with any excess cash flow applied towards debt, working capital or strategic acquisitions. The capital expenditure budget is subject to change depending upon a number of factors, including economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our development and exploration efforts, the availability of sufficient capital resources to us and other participants for drilling prospects, our financial results, the availability of leases on reasonable terms and our ability to obtain permits for the drilling locations. In December 2008, we announced an exploratory and development budget of $43.8 million for 2009. We will continue to monitor commodity prices and operating expenses to determine any further adjustments to the capital budget, and will materially reduce our 2009 budget unless commodity prices strengthen. A further reduction in capital expenditures would materially reduce our production volumes and revenues from pre-2009 levels and increase future development costs for our existing reserves.

Credit facility

We have a $200.0 million revolving credit facility with a borrowing base set at $100.0 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. Our next scheduled redetermination date is April 1, 2009.

The maturity date under our revolving credit facility is July 31, 2010. Borrowings bear interest based on the agent bank's prime rate, or the sum of the LIBOR plus an applicable margin ranging from 1.25% to 2.00% based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.375% of non-used borrowings available under our revolving credit facility.

We had outstanding borrowings of $43.5 million under our revolving credit facility at December 31, 2008. The interest rate applicable to our outstanding borrowings was 3.3% and 6.6% as of December 31, 2008 and December 31, 2007, respectively. We also have outstanding unused letters of credit under our revolving credit facility totaling $400,000 at December 31, 2008, which reduce amounts available for borrowing under our revolving credit facility.

The agent bank, other participating banks and their respective commitment percentages are as follows: The Frost National Bank (agent bank) — 30%, JPMorgan Chase Bank, NA — 30%, Fortis Capital Corp. — 20% and KeyBank National Association — 20%.

Our revolving credit facility contains financial and other covenants that:

- require maintenance of a minimum modified ratio of current assets to current liabilities of 1.0 to 1.0,
- require maintenance of a debt to EBITDAX ratio of 3.5 to 1.0 or less, and
- restrict 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.

We were in compliance with the covenants under our revolving credit facility at December 31, 2008.

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

Current credit market conditions have resulted in lenders significantly tightening their lending practices. 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.

We cannot predict with certainty the impact to us of any further disruption in the credit environment or guarantee that the lenders under our revolving credit facility will not decrease our borrowing base in the future. If our borrowing base was decreased below our total outstanding borrowings, resulting in a borrowing base deficiency, then we would be required under the credit agreement, within 15 days after notice from the agent bank, to (i) pledge additional collateral to cure the borrowing base deficiency, (ii) prepay the borrowing base deficiency in full, or (iii) commit to prepay the borrowing base deficiency in six equal monthly installments, with the first installment being due within 30 days after receipt of notice from the agent bank. There is no guarantee that, in the event of such a borrowing base deficiency, we would be able to timely cure the deficiency.

At February 28, 2009, we had $47.4 million outstanding under our revolving credit facility.

Contractual commitments

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

Our long-term debt is composed of borrowings under our revolving credit facility. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Credit Facility" and Note 5 — Line of Credit for a discussion of our revolving credit facility.

We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital is incurred or rig services are provided. Our commitment under the drilling contracts is $2.8 million at December 31, 2008.

In April 2007, we signed a five-year lease for approximately 13,000 square feet of new office space in Fort Worth, Texas. In August 2008, we expanded our office space under an amendment to the lease to approximately 18,000 square feet. In January 2009, we began rent payments of approximately $30,000 per month, including common area expenses. We have a lease for our prior space in Fort Worth that expires in May 2009. Our remaining obligation under this lease is approximately $10,000 per month until expiration in May 2009. At December 31, 2008, we had signed subleases for all of our prior office space.

We have outstanding employment agreements with executive officers that contain automatic renewal provisions providing that such agreements may be automatically renewed for successive terms of one year unless employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, was approximately $1.1 million at December 31, 2008.

The following table summarizes these commitments as of December 31, 2008 (in thousands):

Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt(1)	$43,537	$ —	$43,537	$ —	$ —
Daywork drilling contracts(2)	2,790	2,790			
Operating lease obligations(3)	1,531	428	779	324	—
Asset retirement obligations(4)	4,225	—	—	—	4,225
Employment agreements with executive officers	1,100	1,100	—	—	—
Total	$53,183	$4,318	$44,316	$324	$4,225

(1) See Note 5 — Line of Credit to our consolidated financial statements for a discussion of our revolving credit facility.

(2) Daywork drilling contracts related to two drilling rigs contracted through March 31,2008.

(3) Operating lease obligations are for office space. We will receive $49,000 for office space that has been subleased from January 2009 through May 2009.

(4) See Note 1 — Summary of Significant Accounting Policies 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, 2008, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit, operating lease agreements and gas transportation commitments. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

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

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

Commodity price risk

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

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

At December 31, 2008, we have the following commodity derivative positions outstanding:

	Volume (MMBtu)		$/MMBtu		
Period	**Monthly**	**Total**	**Floor**	**Ceiling**	**Fixed**
NYMEX — Henry Hub					
Costless collars 2009	180,000	2,160,000	$7.50	$10.50	
Costless collars 2009	130,000	1,560,000	$8.50	$11.70	
WAHA differential					
Fixed price swaps 2009	200,000	2,400,000			(0.61)

At December 31, 2008 and December 31, 2007, the fair value of our open derivative contracts was an asset of approximately $8.0 million and $868,000, respectively.

J.P. Morgan Ventures Energy Corporation is currently the only counterparty to our commodity derivatives positions. We are exposed to credit losses in the event of nonperformance by the counterparty on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparty over the term of the commodity derivatives positions. JPMorgan Chase Bank, NA is a participant in our revolving credit facility and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

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

For the year ended December 31, 2008, we recognized an unrealized gain of $7.1 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2007, we recognized an unrealized loss of $3.6 million from the change in the fair value of commodity derivatives. A 10% increase in the NYMEX floating prices would have resulted in a $1.7 million decrease in the December 31, 2008 fair value recorded on our balance sheet, and a corresponding decrease to the gain on commodity derivatives in our statement of operations.

Effective January 1, 2008, we adopted FAS 157, which among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in FAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). 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. FAS 157 establishes a fair value 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 defined by FAS 157 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, 2008, 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, 2008, 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.

Item 8. ***Financial Statements and Supplementary Data.***

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

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

None.

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

Disclosure controls and procedures

Our management, with the participation of our President and Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2008. Based on this evaluation, our President and Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2008, 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

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, 2008. Hein & Associates LLP, or Hein, our registered public accountants, also attested to, and reported on, management's assessment of the effectiveness of 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.

No changes to our internal control over financial reporting occurred during the year ended December 31, 2008 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, "Directors, Executive Officers and Corporate Governance" will be contained under the captions "Election of Directors — Directors" and "Executive Officers" to be provided in our proxy statement for our 2009 annual meeting of stockholders to be filed with the SEC on or before April 30, 2009, which are incorporated herein by reference. Additional information regarding our corporate governance guidelines as well as the complete texts of our Code of Conduct and the charters of our Audit Committee and our Nominating and Compensation Committee may be found on our website at *www.approachresources.com.*

Item 11. *Executive Compensation.*

Information required by Item 11 of this report will be contained under the caption "Executive Compensation" in our proxy statement for our 2009 annual meeting of stockholders to be filed with the SEC on or before April 30, 2009, which is incorporated herein by reference.

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

Except as set forth below, the information required by Item 12 of this report will be contained under the caption "Stock Ownership Matters" in our proxy statement for our 2009 annual meeting of stockholders to be filed with the SEC on or before April 30, 2009, which is incorporated herein by reference.

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

Information required by Item 13 of this report will be contained under the captions "Certain Relationships and Related Party Transactions" and "Corporate Governance" in our definitive proxy statement for our 2009 annual meeting of stockholders to be filed with the SEC on or before April 30, 2009, which are incorporated herein by reference.

Item 14. *Principal Accountant 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 2009 annual meeting of stockholders to be filed with the SEC on or before April 30, 2009, which is incorporated herein by reference.

PART IV

Item 15. *Exhibits and 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 54 for a description of the exhibits filed as part of this report.

GLOSSARY OF SELECTED OIL AND GAS TERMS

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

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

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

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

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

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

Completion. The installation of permanent equipment for the production of oil or gas.

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

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

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

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

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

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

Farmout. An agreement whereby the owner of a leasehold or working interest agrees to assign an interest in certain specific acreage to the assignees, retaining an interest such as an overriding royalty interest, an oil and gas payment, offset acreage or other type of interest, subject to the drilling of one or more specific wells or other performance as a condition of the assignment.

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

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

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

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

LNG. Liquefied natural gas.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

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

MMBoe. Million barrels of oil equivalent, with six Mcf of natural gas being equivalent to one barrel of oil.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of gas.

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

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

NGLs. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

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

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

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

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as follows:

> Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as follows:

> Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.
>
> (i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
>
> (ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
>
> (iii) Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural

gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

> Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved 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 tests in the area and in the same reservoir.

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

Reserve life index. This index is calculated by dividing year-end 2008 reserves by estimated 2008 production of 8,755 MMcfe to estimate the number of years of remaining production.

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

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

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

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

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

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

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

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 13, 2009

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 13, 2009.

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/ 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, 2008. 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, 2008, 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 13, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.
Fort Worth, Texas

We have audited Approach Resources Inc. and subsidiaries' (collectively, the "Company") internal control over financial reporting as of December 31, 2008, 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, 2008, 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, 2008 and 2007, 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, 2008 and our report dated March 9, 2009, expressed an unqualified opinion.

/s/ HEIN & ASSOCIATES LLP
Dallas, Texas
March 9, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.
Fort Worth, Texas

We have audited the accompanying consolidated balance sheets of Approach Resources Inc. and subsidiaries (collectively, the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of operations, change in stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 9, 2009 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

*/s/ **HEIN** & ASSOCIATES LLP*
Dallas, Texas
March 9, 2009

Approach Resources Inc. and Subsidiaries

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

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,077	$ 4,785
Accounts receivable:		
Joint interest owners	16,228	5,272
Oil and gas sales	5,936	5,524
Unrealized gain on commodity derivatives	8,017	793
Prepaid expenses and other current assets	579	432
Total current assets	34,837	16,806
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	362,805	267,246
Furniture, fixtures and equipment	977	433
	363,782	267,679
Less accumulated depletion, depreciation and amortization	(60,378)	(36,860)
Net properties and equipment	303,404	230,819
OTHER ASSETS	—	1,101
Total assets	$338,241	$248,726
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 13,564	$ 5,459
Oil and gas sales payable	4,631	1,794
Accrued liabilities	12,580	14,764
Total current liabilities	30,775	22,017
NON-CURRENT LIABILITIES:		
Long-term debt	43,537	—
Deferred income taxes	35,891	26,342
Asset retirement obligations	4,225	548
Total liabilities	114,428	48,907
COMMITMENTS AND CONTINGENCIES (Note 11)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value, 10,000,000 shares authorized none outstanding	—	—
Common stock, $0.01 par value, 90,000,000 shares authorized, 20,715,357 and 20,622,746 issued and 20,680,584 and 20,622,746 outstanding, respectively	207	206
Additional paid-in capital	167,349	166,141
Retained earnings	56,753	33,367
Accumulated other comprehensive income	(496)	105
Total stockholders' equity	223,813	199,819
Total liabilities and stockholders' equity	$338,241	$248,726

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)

	December 31, 2008	December 31, 2007	December 31, 2006
REVENUES:			
Oil and gas sales	$ 79,869	$ 39,114	$ 46,672
EXPENSES:			
Lease operating	7,621	3,815	3,889
Severance and production taxes	4,202	1,659	1,736
Exploration	1,478	883	1,640
Impairment of non-producing properties	6,379	267	558
General and administrative	8,881	12,667	2,416
Depletion, depreciation and amortization	23,710	13,098	14,551
Total expenses	52,271	32,389	24,790
OPERATING INCOME	27,598	6,725	21,882
OTHER:			
Impairment of investment	(917)	—	—
Interest expense, net	(1,269)	(5,219)	(3,814)
Realized gain on commodity derivatives	2,936	4,732	6,222
Unrealized gain (loss) on commodity derivatives	7,149	(3,637)	8,668
INCOME BEFORE INCOME TAX PROVISION	35,497	2,601	32,958
INCOME TAX PROVISION (BENEFIT)	12,111	(108)	11,756
NET INCOME	$ 23,386	$ 2,709	$ 21,202
EARNINGS PER SHARE:			
Basic	$ 1.13	$ 0.25	$ 2.26
Diluted	$ 1.12	$ 0.24	$ 2.20
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	20,647,339	10,976,251	9,368,614
Diluted	20,824,905	11,183,707	9,634,912

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, 2006, 2007 and 2008 (In thousands, except shares and per-share amounts)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Loans to Stockholders, Including Accrued Interest	Accumulated Other Comprehensive Income	Total
	Shares	Amount					
BALANCES, January 1, 2006	9,179,721	$ 92	34,440	$ 9,456	$(4,298)	$ —	$ 39,690
Purchase and cancellation of common stock	(103,845)	(1)	(1,330)	—	334	—	(997)
Issuance of common stock	428,634	4	6,494	—	—	—	6,498
Issuance of common stock for conversion of stockholder note	230,802	2	3,498	—	—	—	3,500
Stock option cancellation payment	—	—	(273)	—	—	—	(273)
Share-based compensation expense	—	—	34	—	—	—	34
Accrual of interest on loans to stockholders, net of related income tax	—	—	138	—	(220)	—	(82)
Net income	—	—	—	21,202	—	—	21,202
BALANCES, December 31, 2006	9,735,312	97	43,001	30,658	(4,184)	—	69,572
Retirement of loans to stockholders	(253,650)	(2)	(4,182)	—	4,184	—	—
Issuance of common shares to management and directors for compensation	411,041	4	(4)	—	—	—	—
Issuance of stock upon exercise of stock options	72,114	1	239	—	—	—	240
Share-based compensation expense	—	—	4,646	—	—	—	4,646
Issuance of common stock upon conversion of convertible notes	1,841,262	18	20,530	—	—	—	20,548
Beneficial conversion feature of convertible notes	—	—	1,547	—	—	—	1,547
Issuance of shares in initial public offering	6,598,572	66	73,574	—	—	—	73,640
Offering costs related to the initial public offering	—	—	(1,503)	—	—	—	(1,503)
Issuance of shares for acquisition of oil and gas properties	4,239,243	42	50,829	—	—	—	50,871
Purchase and cancellation of common stock	(2,021,148)	(20)	(22,536)	—	—	—	(22,556)
Net income	—	—	—	2,709	—	—	2,709
Foreign currency translation adjustments	—	—	—	—	—	105	105
BALANCES, December 31, 2007	20,622,746	206	166,141	33,367	—	105	199,819
Issuance of stock upon exercise of stock options	63,459	1	212	—	—	—	213
Restricted stock issuance	29,152	—	—	—	—	—	—
Share-based compensation expense	—	—	1,100	—	—	—	1,100
Surrender of restricted shares for payment of income taxes	—	—	(54)	—	—	—	(54)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(50)	—	—	—	(50)
Net income	—	—	—	23,386	—	—	23,386
Foreign currency translation adjustments, net of related income tax of $256	—	—	—	—	—	(601)	(601)
BALANCES, December 31, 2008	20,715,357	$207	$167,349	$56,753	$ —	$(496)	223,813

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,		
	2008	2007	2006
OPERATING ACTIVITIES:			
Net income	$ 23,386	$ 2,709	$ 21,202
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	23,710	13,098	14,551
Non-cash interest expense on convertible notes	—	2,095	—
Unrealized (gain) loss on commodity derivatives	(7,149)	3,637	(8,668)
Impairment of non-producing properties	6,379	267	558
Impairment of investment	917	—	—
Exploration expense	1,478	883	1,614
Share-based compensation expense	1,100	4,646	34
Deferred income taxes	12,148	(296)	11,102
Changes in operating assets and liabilities:			
Accounts receivable	(11,501)	(2,657)	7,389
Prepaid expenses and other current assets	(38)	(232)	293
Accounts payable	8,105	(787)	(14,284)
Oil and gas sales payable	2,837	(3,146)	(1,704)
Accrued liabilities	(4,937)	10,529	2,218
Cash provided by operating activities	56,435	30,746	34,305
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(100,089)	(51,845)	(59,352)
Additions to furniture, fixtures and equipment, net	(544)	(178)	(32)
Investments	—	(917)	—
Cash used in investing activities	(100,633)	(52,940)	(59,384)
FINANCING ACTIVITIES:			
Loan origination fees	—	(140)	(69)
Borrowings under credit facility	121,687	64,285	119,547
Repayment of amounts outstanding under credit facility	(78,150)	(111,904)	(101,353)
Proceeds from convertible notes	—	20,000	—
Borrowing from stockholder	—	—	3,500
Proceeds from issuance of common stock	213	72,377	6,498
Surrender of restricted shares for payment of income taxes	(54)	—	—
Purchase of common stock	—	(22,556)	(997)
Stock option cancellation payment	—	—	(273)
Income taxes on interest income from loans to stockholders	—	—	(82)
Cash provided by financing activities	43,696	22,062	26,771
CHANGE IN CASH AND CASH EQUIVALENTS	(502)	(132)	1,692
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	(206)	6	—
CASH AND CASH EQUIVALENTS, beginning of year	4,785	4,911	3,219
CASH AND CASH EQUIVALENTS, end of year	$ 4,077	$ 4,785	$ 4,911
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 894	$ 4,117	$ 3,269
Cash paid for income taxes	$ 397	$ 1,287	$ 2
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Conversion of stockholder note into common stock	$ —	$ —	$ 3,500
Acquisition of oil and gas properties	$ 509	$ 60,225	$ —
Asset retirement obligations capitalized	$ 3,504	$ 257	$ 31
Conversion of convertible notes and accrued interest into common stock	$ —	$ 20,548	$ —
Retirement of loans to stockholders in exchange for shares of common stock	$ —	$ 4,184	$ 334

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,		
	2008	2007	2006
Net income	$23,386	$2,709	$21,202
Other comprehensive (loss) income:			
Foreign currency translation, net of related income tax	(601)	105	—
Total comprehensive income	$22,785	$2,814	$21,202

See accompanying notes to these consolidated financial statements.

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

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

Consolidation, Basis of Presentation and Significant Estimates

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

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

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

Cash and Cash Equivalents

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

Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, notes receivable, accounts payable and accrued liabilities and long-term debt approximate fair value, as of December 31, 2008 and 2007. See Note 8 for commodity derivative fair value disclosures.

Oil and Gas Properties and Operations

Capitalized Costs

Our oil and gas properties comprised the following at December 31, (in thousands):

	2008	2007
Mineral interests in properties:		
Unproved properties	$ 12,687	$ 10,845
Proved properties	11,849	10,937
Wells and related equipment and facilities	332,289	234,067
Uncompleted wells, equipment and facilities	5,980	11,397
Total costs	362,805	267,246
Less accumulated depreciation, depletion and amortization	(59,960)	(36,622)
	$302,845	$230,624

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 found proved reserves. If we determine that the wells do not find proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determination of whether the wells found proved reserves at December 31, 2008 or 2007. 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, 2008, 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 6 Mcf of gas to 1 Bbl of oil. Depreciation and depletion expense for oil and gas producing property and related equipment was $23.3 million, $13.0 million and $14.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. We recorded an impairment of $6.4 million and $267,000 during the years ended December 31, 2008 and 2007, respectively related to our assessment of unproved properties. The impairment recorded during the year ended December 31, 2008, resulted from write-offs related to drilling costs in our Boomerang project and drilling and completion costs in our Northeast British Columbia project. During the year ended December 31, 2008, we determined that the future cash flows from drilling costs relating to these projects will not exceed the capitalized costs due to market factors. The impairment recorded during the year ended December 31, 2007, resulted from our conclusion that proved reserves would not be economically recovered from approximately 2,282 acres in Ozona Northeast, leases for which expired in April 2008. We recorded a $558,000 impairment during the year ended December 31, 2006, which resulted from our leaseholds in our Pecos County, Texas prospect because we drilled dry holes on the prospect and decided to abandon drilling efforts in this area.

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 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 unproved properties and their estimated fair values based on the present value of the related future net cash flows. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2008, 2007 or 2006.

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.

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, 2008 or 2007.

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.

Production Costs

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

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

Dependence on Major Customers

For the years ended December 31, 2008, 2007 and 2006, 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, 2008 and 2007. 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.

Dependence on Suppliers

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

Other Property

Furniture, fixtures and equipment are carried at cost. Depreciation of furniture, fixtures and equipment is provided using the straight-line method over estimated useful lives ranging from three to ten years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition. Depreciation expense for other property and equipment was $180,000, $88,000 and $64,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Income Taxes

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

Derivative Activity

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

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

Accrued Liabilities

Following is a summary of our accrued liabilities at December 31, 2008 and 2007:

	2008	2007
Capital expenditures accrued	$ 8,173	$13,168
Operating expenses and other	1,587	1,380
Deferred income tax liabilities	2,770	—
Income taxes payable	50	216
	$12,580	$14,764

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. Following is a summary of our asset retirement obligations for the year ended December 31, 2008:

Balance, beginning of period	$ 548
Acquisitions/drilled wells	1,505
Accretion of discount	191
Change in assumptions	1,981
Balance, end of period	$4,225

The change in assumptions relate primarily to the decrease in the credit adjusted risk free rate used to value the asset retirement obligations. The change in the asset retirement obligations for the twelve months ended December 31, 2007 and 2006 was not significant.

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, 2008 and 2007, we recognized a $601,000 translation loss, net of the related income tax, and a $105,000 translation gain, respectively. Transaction gains and losses for the year ended December 31, 2006 were insignificant.

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):

	Year Ended December 31, 2008		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net income	$23,386	20,647,339	$1.13
Effect of dilutive securities(1):			
Stock options, treasury method	—	177,566	
Net income plus assumed conversions	$23,386	20,824,905	$1.12

	Year Ended December 31, 2007		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net income	$2,709	10,976,251	$0.25
Effect of dilutive securities:			
Stock options, treasury method		146,908	
Non-vested restricted shares(2)		60,548	
Convertible notes(3)	—	—	
Net income plus assumed conversions	$2,709	11,183,707	$0.24

	Year Ended December 31, 2006		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net income	$21,202	9,368,614	$2.26
Effect of dilutive securities:			
Stock options, treasury method	—	266,298	
Net income plus assumed conversions	$21,202	9,634,912	$2.20

(1) Approximately 35,000 non-vested restricted shares were excluded from assumed conversions because they were anti-dilutive for the year ended December 31, 2008.

(2) We issued these shares in March 2007. Prior to that time, there were no restricted shares outstanding.

(3) The outstanding principal and interest under our convertible debt was converted on November 7, 2007 into shares of common stock (see Note 3 for further discussion). Approximately 1.8 million shares were excluded from assumed conversions because they were anti-dilutive for the year ended December 31, 2007.

The share amounts for the year ending 2006 have been restated to reflect the contribution agreement and the stock split discussed in Note 3.

Recently Issued Accounting Pronouncements

In March 2008, the Financial Accounting Standards Board, or FASB, issued Statement of Financial Accounting Standard 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of

FASB Statement 133, or SFAS 161. SFAS 161 amends and expands the disclosure requirements of FASB Statement 133 with the intent to provide users of financial statement with an enhanced understanding of (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and the related hedged items are accounted for under FASB Statement 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect and entity's financial position, financial performance and cash flows. SFAS 161 is effective for financial statements issued for years and interim periods beginning after November 15, 2008. The effect of adopting SFAS 161 is not expected to have a significant effect on our reported financial position or earnings.

In December 2007, FASB issued Statement of Financial Accounting Standards 141 (revised 2007), *Business Combinations*, or SFAS 141(R). SFAS 141(R), among other things, establishes principles and requirements for how the acquirer in a business combination (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquired business, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning on or after December 15, 2008, with early adoption prohibited. This standard will change our accounting treatment for business combinations on a prospective basis.

In December 2007, the FASB issued Statement of Financial Accounting Standards 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51*, or SFAS 160. SFAS 160 establishes accounting and reporting standards for noncontrolling interests in a subsidiary and for the deconsolidation of a subsidiary. Minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. It also establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary and requires expanded disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008, with early adoption prohibited. The effect of adopting SFAS 160 is not expected to have a significant effect on our reported financial position or earnings.

Recent Developments in Reserve Reporting

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting*, updating its oil and gas reporting requirements. The new reporting requirements will be effective for our financial statements for the year ending December 31, 2009 and our 2009 year-end proved reserve estimates. The new reporting requirements include provisions that:

- Permit the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes,
- Allow companies to disclose their probable and possible reserves in SEC-filed documents (currently, SEC rules limit disclosure to only proved reserves),
- Require companies to report the independence and qualifications of a reserves preparer or auditor,
- Require companies to file a report when a third party is relied upon to prepare reserves estimates or conducts a reserves audit, and
- Require companies to report oil and gas reserves using an average price based upon the prior 12-month period (rather than year-end prices).

We are currently evaluating the impact that these new reporting requirements will have for the year ended December 31, 2009.

2. Ozona Northeast deep rights acquisition

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

The purchase price was $12.0 million subject to post-closing adjustments. We received a post-closing settlement of $1.1 million subsequent to December 31, 2008. Of the purchase price, $500,000 is to be paid no later than one year from closing pending certain right-of-way matters being cured. Our preliminary purchase price allocation was $9.5 million to oil and gas properties and $2.0 million to gathering system, compression facilities and related equipment. Funding was provided through borrowings under our revolving credit facility.

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

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

3. Contribution Agreement and Initial Public Offering

Contribution Agreement

On November 14, 2007, the Company acquired all of the outstanding capital stock of AOG and acquired the 30% working interest in the Ozona Northeast field (the "Neo Canyon interest") that the Company did not already own from Neo Canyon Exploration, L.P. ("Neo Canyon"). Upon the closing of the contribution agreement, Neo Canyon and each of the stockholders of AOG received shares of Company common stock in exchange for their respective contributions. Neo Canyon received an aggregate of 4,239,243 shares of Company common stock, of which 2,061,290 shares were offered in the Company's IPO, 156,805 shares were subject to the over-allotment option granted to the underwriters and 2,021,148 shares were redeemed by the Company for cash. The stockholders of AOG received an aggregate of 989,157 shares of Company common stock.

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

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

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

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

Initial Public Offering

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

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

Stock Split

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

Convertible Notes

Upon the consummation of the IPO, the convertible notes discussed in Note 9, Convertible Notes, and related accrued interest were automatically converted into shares of our common stock. The number of shares of common stock issued upon the automatic conversion of these notes was 920,631 to Yorktown Energy Partners VII, L.P. and 920,631 to Lubar Equity Fund, LLC. The shares of common stock that were issued to Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC upon such automatic conversion are entitled to the same registration rights as those provided to certain holders of common stock in connection with the contribution agreement.

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

4. Loans to Stockholders and Stockholder Notes Payable

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

During February 2006, one of our employees voluntarily resigned. At the time of his resignation, the employee held 103,845 shares of ARI common stock and options to acquire 28,845 shares of ARI common stock at $3.33 per share. Additionally, the employee owed us $334,000 of principal and interest under a full-recourse note receivable for the initial purchase of his shares. On February 17, 2006, we entered into an agreement to repurchase the shares and options, net of the principal and interest due under the note receivable. We paid $12.82 per share, the fair value of our common stock on February 17, 2006, for the 103,845 shares, or $1.3 million less the outstanding principal and interest of $334,000 for total cash of $1.0 million. As discussed in Note 6, Share-Based Compensation, we paid $273,000 in cash to cancel the vested options held by the employee on February 17, 2006.

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

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

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

On April 17, 2006, we borrowed $3.5 million from a stockholder to fund the acquisition of leaseholds in Kentucky. The terms of the borrowing provided for interest at 6 percent and was due on demand. The borrowing was settled through the issuance of 230,822 shares of common stock on July 5, 2006.

5. Line of Credit

We have a $200.0 million revolving loan agreement ("Loan Agreement") with a borrowing base set at $100.0 million and which 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 the Loan Agreement is July 31, 2010. The borrowings bear interest based on the agent bank's prime rate, or the sum of the LIBOR plus an applicable margin ranging from 1.25% to 2.00% based on the borrowings outstanding compared to the borrowing base. We had outstanding borrowings of $43.5 million at December 31, 2008. We had no outstanding borrowings at December 31, 2007. The interest rate applicable to our outstanding borrowings was 3.3% and 6.6% as of December 31, 2008 and December 31, 2007, respectively. We were in compliance with the covenants in the Loan Agreement at December 31, 2008. There are certain restrictions of the payment of dividends defined in the Loan Agreement that can be waived by the consent of lenders.

On February 19, 2008, we entered into an amendment ("First Amendment") to our Loan Agreement dated as of January 18, 2008, among the Company, as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, as lender, and AOG, Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors. The First Amendment (i) waives the provisions of Sections 13(a)(ii) and 13(g) of the Loan Agreement to the extent that such sections would prohibit the transfer of oil and gas properties between the Company and any guarantor or between guarantors under the Loan Agreement, and (ii) amends Section 13(a)(ii) of the Loan Agreement to permit the transfer of oil and gas properties between the Company and any guarantor or between guarantors under the Credit Agreement. Currently, all guarantors under the Loan Agreement are direct or indirect wholly-owned subsidiaries of the Company.

On May 6, 2008, we entered into a second amendment (the "Second Amendment") to the Loan Agreement. The Second Amendment reflected an increase in our borrowing base and commitments of the lenders to $100 million.

On August 26, 2008, we entered into a third amendment (the "Third Amendment") to the Loan Agreement. The Third Amendment (i) added Fortis Capital Corp. and KeyBank National Association as lenders under the Credit Agreement, (ii) allocated the lenders' commitment percentages as The Frost National Bank — 30%, JPMorgan Chase Bank, NA — 30%, Fortis Capital Corp. — 20% and KeyBank National Association — 20%, (iii) added a covenant that we will not exceed a debt to EBITDAX ratio of 3.5 to 1.0, and (iv) clarified that secured parties under the Loan Agreement (and beneficiaries of Loan Agreement guarantees) will include affiliates of lenders who enter into commodity derivatives transactions with us.

We also have outstanding unused letters of credit under the Loan Agreement totaling $400,000 at December 31, 2008, which reduce amounts available for borrowing under the Loan Agreement.

6. 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 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 option award is to be determined by the board at the time of the grant. The term of each stock option is to be fixed at the time of grant and may not exceed 10 years. Shares issued upon stock options exercised are issued as new shares.

Share-based compensation expense amounted to $1.1 million, $4.6 million and $34,000 for the years ended December 31, 2008, 2007 and 2006, respectively. Such amounts represent the estimated fair value of options for which the requisite service period elapsed during the years. There was no tax benefit recognized in relation to this change.

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the years ended December 31, 2008 and 2007. There were no grants during the year ended December 31, 2006.

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

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

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

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

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

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

The following table summarizes stock options outstanding and activity as of and for the years ended December 31, 2008, 2007 and 2006, (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, 2006	375,000	$ 3.33		
Canceled	(28,845)	$ 3.33		
Outstanding at December 31, 2006	346,155	$ 3.33		
Granted	205,950	$12.05		
Exercised	(72,114)	$ 3.33		
Outstanding at December 31, 2007	479,991	$ 7.07	8.02	$2,779
Granted	74,345	$14.90		
Exercised	(63,459)	$ 3.33		
Canceled	(56,575)	$12.40		
Outstanding at December 31, 2008	434,302	$ 8.47	7.34	$ 837
Exercisable (fully vested) at December 31, 2008	262,557	$ 5.07	6.27	$ 837

The outstanding share amounts at January 1, 2006 and December 31, 2006 have been restated to reflect the contribution agreement and the stock split discussed in Note 3.

The fair market value of the stock options granted during the years ended December 31, 2008 and 2007 was $8.96 per share and $7.69 per share, respectively. Total unrecognized share-based compensation expense from unvested stock options as of December 31, 2008 was $1.2 million, and will be recognized over a remaining service period of 2.25 years. The intrinsic value of the options exercised during the years ended December 31, 2008 and 2007 was $770,000 and $634,000, respectively.

During the year ended December 31, 2006, we paid $273,000 in cash to cancel the vested options held by an employee who voluntarily resigned. Such amount has been recorded as a reduction to additional paid in capital as the payment did not exceed the estimated fair value of the options at the time of the cancellation.

Share grants totaling 35,948 and 411,041 shares with an approximate aggregate market value of $733,000 and $5.2 million at the time of grant were granted during the years ended December 31, 2008 and 2007, respectively. A summary of the status of non-vested shares for the years ended December 31, 2008 and 2007, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2007	—	$ —
Granted	411,041	12.70
Vested	(368,541)	12.26
Nonvested at December 31, 2007	42,500	16.50
Granted	35,948	20.39
Vested	(21,250)	16.50
Canceled	(1,175)	15.48
Nonvested at December 31, 2008	56,023	$18.96

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

7. Income Taxes

Our provision (benefit) for income taxes comprised the following during the years ended December 31, 2008, 2007 and 2006 (in thousands):

	2008	2007	2006
Current:			
Federal	$ (214)	$ 188	$ 550
State	177	—	105
Total current	(37)	188	655
Deferred:			
Federal	11,919	(296)	11,243
State	229	—	(141)
Total deferred	12,148	(296)	11,102
Provision (benefit) for income taxes	$12,111	$(108)	$11,757

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. Federal statutory tax rates to pre-tax income for the years ended December 31, 2008, 2007 and 2006, as follows (in thousands):

	2008	2007	2006
Statutory tax at 34%	$12,069	$ 884	$11,205
State taxes, net of federal impact	199	29	990
Changes in enacted rates	—	—	(1,077)
Permanent differences(1)	235	609	—
Other differences	(392)	(35)	(173)
Change in valuation allowance	—	(1,595)	812
	$12,111	$ (108)	$11,757

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

In May 2006, the State of Texas enacted a margin tax which will require us to pay a tax of 1.0% on our "taxable margin," as defined in the law, based on our operating results beginning January 1, 2007. The margin to which the tax rate will be applied generally will be calculated as our gross revenues for federal income tax purposes less the cost of goods sold, as defined for Texas margin tax purposes. Cost of goods sold includes the following expenses that are related to our production of goods: our lease operating expenses, production taxes, depletion and depreciation expense, labor costs and intangible drilling costs. Most of our operations are within the State of Texas. Under the provisions of Statement of Financial Accounting Standards 109, Accounting for Income Taxes, we are required to record the effects on deferred taxes for a change in tax rates or tax law in the period which includes the enactment date. Previously, our results of operations were subject to the franchise tax in Texas at a rate of 4.5%, before consideration of federal benefits of those state taxes. Temporary differences between book and tax income related to our oil and gas properties will affect our computation of the Texas margin tax, and we reduced our deferred tax liabilities by $1.1 million as of December 31, 2006 as the result of this change.

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 $35.9 million and $26.3 million at December 31, 2008 and 2007, respectively. At December 31, 2008, $2.8 million of deferred taxes expected to be settled during 2009 was included in current liabilities within accrued expenses. Significant components of net deferred tax assets and liabilities are (in thousands):

	December 31,	
	2008	2007
Deferred tax assets:		
Net operating loss carryforwards	$ 2,363	$ 2,846
Other	694	—
Total deferred tax assets	$ 3,057	$ 2,846
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods — oil and gas properties	(38,948)	(28,877)
Unrealized gain on commodity derivatives	(2,770)	(301)
Other	—	(10)
Total deferred tax liabilities	(41,718)	(29,188)
Net deferred tax (liability)	$(38,661)	$(26,342)

At December 31, 2006, AOG provided a valuation allowance related to its deferred tax assets resulting primarily from net operating loss carryforwards of $1.6 million, based upon management's inability to assess the amount to be realized until completion of the acquisition of AOG capital stock by ARI. The net operating loss carryforwards at December 31, 2007 of $2.8 million above is related to the release of this valuation allowance.

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

Expiration Dates	Amounts
2024	$1,523
2025	1,082
2026	2,594
2027	1,750
Total	$6,949

8. Derivatives

At December 31, 2008, we had the following commodity derivatives positions outstanding:

	Volume (MMBtu)		$/MMBtu		
Period	Monthly	Total	Floor	Ceiling	Fixed
NYMEX — Henry Hub					
Costless collars 2009	180,000	2,160,000	$7.50	$10.50	
Costless collars 2009	130,000	1,560,000	$8.50	$11.70	
WAHA differential					
Fixed price swaps 2009	200,000	2,400,000			(0.61)

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

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

Effective January 1, 2008, we adopted FAS 157, which among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in FAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize 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 utilize the best available information. FAS 157 establishes a fair value 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 defined by FAS 157 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, 2008, 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, 2008, 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.

9. Convertible Notes

On June 25, 2007, Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC loaned an aggregate of $20.0 million to AOG under two convertible promissory notes of $10.0 million each. These notes bore interest at a rate of 7.00% per annum and had a maturity date of June 25, 2010, at which time all principal and interest would have been due. These notes were initially convertible at the election of the lender into shares of equity securities of AOG at $100 per share on December 31, 2007, or earlier if we sold substantially all of the assets of AOG. Upon consummation of our IPO, the notes automatically, and without further action required by any person, converted into shares of ARI common stock. The number of shares of ARI common stock issued upon the automatic conversion of these notes was equal to the quotient obtained by dividing

(a) the outstanding principal and accrued interest on each respective note by (b) the IPO price per share, less any underwriting discount per share for the shares of ARI common stock that were issued in our IPO. The shares of our common stock issued to Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC upon such automatic conversion are entitled to the same registration rights as those provided to certain holders of our common stock in connection with the contribution agreement. The total principal and interest owed under these notes at the time of the IPO was $20.5 million. Yorktown Energy Partners VII, L.P. is an affiliate of Yorktown Partners LLC, which has one representative, Bryan H. Lawrence, who serves as a member of our board of directors. Lubar Equity Fund, LLC is an affiliate of Sheldon B. Lubar, who serves as a member of our board of directors.

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

10. Canadian Unconventional Gas Investment

In May 2007, we acquired shares of common stock of a Canadian-based private exploration company focused on tight gas and shale gas opportunities in Canada. Our investment amounted to approximately $917,000 and is a non-controlling interest accounted for using the cost method at December 31, 2007. We have written off the carrying value of our minority equity investment in the Canadian operator by recognizing a non-cash charge to earnings because we believe we will not recover our investment.

11. Commitments and Contingencies

We have employment agreements with our officers and selected other employees. These agreements are automatically renewed for successive terms of one year unless employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, is approximately $1.1 million at December 31, 2008.

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

We also have non-cancelable operating lease commitments related to office equipment that expire by 2012. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements, net of minimum rentals to be received under non-cancelable subleases as of December 31, 2008 (in thousands):

2009	428
2010	385
2011	394
2012	324
Total	1,531
Less: subleases	(49)
Total	$1,482

Rent expense under our lease arrangements amounted to $299,000, $198,000 and $137,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Litigation

We are involved in various legal and regulatory proceedings arising in the normal course of business. We do not believe that an adverse result in any pending legal or regulatory proceeding, together or in the aggregate, would be material to our consolidated financial condition, results of operations 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.

12. 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 Year Ended December 31,		
	2008	2007	2006
Property acquisition costs:			
Unproved properties	$ 2,695	$ 5,480	$ 4,071
Proved properties	12,189	59,594	356
Exploration costs	5,007	9,897	3,769
Development costs(1)	84,193	37,451	51,820
Total costs incurred	$104,084	$112,422	$60,016

(1) For the year ended December 31, 2008, development costs include $3.5 million in non-cash asset retirement obligations recorded in 2008.

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,		
	2008	2007	2006
Revenues	$ 79,869	$ 39,114	$ 46,672
Production costs	(11,823)	(5,474)	(5,625)
Exploration expense	(1,478)	(883)	(1,640)
Impairment	(6,379)	(267)	(558)
Depletion	(23,338)	(13,010)	(14,487)
Income tax expense	(12,529)	(6,623)	(9,114)
Results of operations	$ 24,322	$ 12,857	$ 15,248

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

The estimates of proved reserves and related valuations for the years ended December 31, 2008, 2007 and 2006 were based upon the reports prepared by DeGolyer and MacNaughton, independent petroleum engineers. Each year's estimate of proved reserves and related valuations was prepared in accordance with the provisions of Statement of Financial Accounting Standards 69, or SFAS 69, Disclosures about Oil and Gas Producing Activities. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. All of our oil and natural gas reserves are attributable to properties within the United States. A summary of Approach's changes in quantities of proved oil and natural gas reserves for the years ended December 31, 2006, 2007 and 2008, are as follows:

	Natural Gas (MMcf)	Oil & NGLs (MBbl)
Balance — January 1, 2006	102,405	1,086
Extensions and discoveries	15,655	339
Production	(6,282)	(77)
Revisions to previous estimates	(13,121)	(226)
Balance — December 31, 2006	98,657	1,122
Extensions and discoveries	36,194	1,807
Purchases of minerals in place	40,174	378
Production	(4,801)	(84)
Revisions to previous estimates	(9,073)	(15)
Balance — December 31, 2007	161,151	3,208
Extensions and discoveries	22,879	3,228
Purchases of minerals in place	7,312	67
Production	(7,092)	(277)
Revisions to previous estimates	(11,383)	141
Balance — December 31, 2008	172,867	6,367
Proved developed reserves:		
December 31, 2006	51,004	496
December 31, 2007	70,251	1,268
December 31, 2008	84,217	3,014

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2008, 2007 and 2006:

Year Ended December 31, 2008

Our drilling programs in Ozona Northeast, Cinco Terry and North Bald Prairie resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. Additionally, during 2008 we acquired 7,711 MMcfe of proved reserves in Ozona Northeast, which accounts for the additional proved reserve quantities listed as purchases of minerals in place. Downward revisions to proved reserves of 7,405 MMcfe are the result of a significant decline in commodity prices during the third and fourth quarters of 2008. The average gas price attributable to our proved reserves decreased from $8.10 per Mcf at December 31, 2007 to $6.04 at December 31, 2008. Downward revisions to proved reserves of 3,132 MMcfe are also the result of performance in Ozona Northeast and North Bald Prairie.

Year Ended December 31, 2007

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

Year Ended December 31, 2006

Our drilling programs in Ozona Northeast and Cinco Terry resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. The average gas price attributable to our proved reserves decreased from $9.20 per Mcf at December 31, 2005 to $6.55 per Mcf at December 31, 2006, which was the primary reason for the decrease in quantities listed under revisions to previous estimates.

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 the provisions of SFAS 69. Future cash inflows were computed by applying prices at year end to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

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

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

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

	2008	2007	2006
Future cash flows	$1,248,661	$1,567,251	$ 709,184
Future production costs	(411,177)	(401,579)	(198,023)
Future development costs	(201,259)	(191,738)	(108,451)
Future income tax expense	(157,503)	(285,384)	(109,784)
Future net cash flows	478,722	688,550	292,926
10% annual discount for estimated timing of cash flows	(336,087)	(472,590)	(215,049)
Standardized measure of discounted future net cash flows	$ 142,635	$ 215,960	$ 77,877

Future cash flows as shown above were reported without consideration for the effects of commodity derivative transactions outstanding at each period end. The effect of commodity derivative transactions on the future cash flows for the years ended December 31, 2008, 2007 and 2006 was immaterial.

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):

	2008	2007	2006
Balance, beginning of period	$ 215,960	$ 77,877	$ 146,439
Net change in sales and transfer prices and in production (lifting) costs related to future production	(148,739)	57,231	(106,246)
Changes in estimated future development costs	(72,754)	(39,506)	(43,229)
Sales and transfers of oil and gas produced during the period	(68,037)	(33,640)	(41,047)
Net change due to extensions, discoveries and improved recovery	58,249	107,864	28,418
Net change due to purchase of minerals in place	10,632	97,328	—
Net change due to revisions in quantity estimates	(14,526)	(21,001)	(22,112)
Previously estimated development costs incurred during the period	89,942	28,026	52,108
Accretion of discount	29,369	12,843	15,546
Other	(8,712)	8,077	(4,303)
Net change in income taxes	51,251	(79,139)	52,303
	$ 142,635	$215,960	$ 77,877

Average wellhead prices in effect at December 31, 2008, 2007 and 2006 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows:

	2008	2007	2006
Oil (per Bbl)	$39.60	$93.30	$58.05
Natural gas liquids (per Bbl)	$23.00	$60.09	$30.55
Gas (per Mcf)	$ 6.04	$ 8.10	$ 6.55

14. Supplementary Data

Selected Quarterly Financial Data (unaudited), (dollars in thousands):

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

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

	2006 Quarter Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 9,885	$10,397	$12,134	$14,256
Net operating expenses	(6,526)	(6,231)	(6,575)	(5,458)
Interest expense, net	(1,047)	(1,058)	(984)	(725)
Realized gain on commodity derivatives	2,012	1,126	1,660	1,424
Unrealized (loss) gain on commodity derivatives	(474)	3,695	(745)	6,192
Income before income taxes	3,850	7,929	5,490	15,689
Income tax provision	1,457	2,865	2,154	5,280
Net income	$ 2,393	$ 5,064	$ 3,336	$10,409
Basic net income applicable to common stockholders per common share	$ 0.25	$ 0.53	$ 0.37	$ 1.14
Diluted net income applicable to common stockholders per common share	$ 0.24	$ 0.52	$ 0.36	$ 1.11

Approach Resources Inc.

Index to Exhibits

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

Exhibit Number	Description of Exhibit
10.15†	Form of Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q filed November 6, 2008 and incorporated herein by reference).
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 Contract dated May 1, 2004 between Ozona Pipeline Energy Company, as Buyer, and Approach Resources I, L.P. and certain other parties identified therein (filed as Exhibit 10.18 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.18	Agreement Regarding Gas Purchase Contract dated May 26, 2006 between Ozona Pipeline Energy Company, as Buyer, and Approach Resources I, L.P. and certain other parties identified therein (filed as Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.19	Carry and Earning Agreement dated July 13, 2007 by and between EnCana Oil & Gas (USA) (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.20	Oil & Gas Lease dated February 27, 2007 between the lessors identified therein and Approach Oil & Gas Inc., as successor to Lynx Production Company, Inc. (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.21	Specimen Oil and Gas Lease for Boomerang prospect between lessors and Approach Oil & Gas Inc., as successor to The Keeton Group, LLC, as lessee (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512) and incorporated herein by reference).
10.22	Lease Crude Oil Purchase Agreement dated May 1, 2004 by and between ConocoPhillips and Approach Operating LLC (filed as Exhibit 10.26 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512) and incorporated herein by reference).
10.23	Gas Purchase Agreement dated as of November 21, 2007 between WTG Benedum Joint Venture, as Buyer, and Approach Oil & Gas Inc. and Approach Operating, LLC, as Seller (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 28, 2007 and incorporated herein by reference).
10.24	$200,000,000 Revolving Credit Agreement dated as of January 18, 2008 among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, and the financial institutions named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 25, 2008 and incorporated herein by reference).
10.25	Amendment dated February 19, 2008 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, as lender, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 22, 2008 and incorporated herein by reference).
10.26	Amendment dated May 6, 2008 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, as lender, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K filed August 28, 2008 and incorporated herein by reference).
10.27	Amendment dated August 26, 2008 to Credit Agreement among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors, dated as of January 18, 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 28, 2008 and incorporated herein by reference).

Exhibit Number	Description of Exhibit
14.1	Code of Conduct (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K filed March 28, 2008 and incorporated herein by reference).
*21.1	Subsidiaries.
*23.1	Consent of Hein & Associates LLP.
*23.2	Consent of DeGolyer and MacNaughton.
*31.1	Certification by the President and Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification by the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification by the Chief Financial Officer Pursuant to U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

† Denotes management contract or compensatory plan or arrangement.

Supplemental Non-GAAP Financial Information

Adjusted Net Income

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

(i) impairment of long-lived assets,

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

(iii) related income taxes.

The amounts included in the calculation of adjusted net income and adjusted earnings per diluted share below were computed in accordance with GAAP. We believe adjusted net income and adjusted earnings 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, our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table provides a reconciliation of net income to adjusted net income (in thousands, except per-share metrics):

	Twelve Months Ended December 31,		
	2008	2007	2006
Net income	$23,386	$ 2,709	$21,202
Impairment of non-producing properties	6,379	267	558
Impairment of investment	917	—	—
Unrealized (gain) loss on commodity derivatives	(7,149)	3,637	(8,668)
Related income tax effect for above items	(50)	(1,327)	2,757
Adjusted net income	$23,483	$ 5,286	$15,849
Adjusted earnings per diluted share	$ 1.13	$ 0.47	$ 1.64

EBITDAX

We define EBITDAX as net income, plus (1) exploration expense, (2) impairments of long-lived assets, (3) depletion, depreciation and amortization expense, (4) share-based compensation expense, (5) unrealized (gain) loss on commodity derivatives, (6) interest expense and (7) income taxes. EBITDAX is not a measure of net income or cash flow as determined by GAAP. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. EBITDAX is reconciled to the GAAP measure of net income and included in this report 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. However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table provides a reconciliation of net income to EBITDAX (in thousands, except per-share metrics):

	Twelve Months Ended December 31,		
	2008	2007	2006
Net income	$23,386	$ 2,709	$21,202
Exploration	1,478	883	1,640
Impairment of non-producing properties	6,379	267	558
Depletion, depreciation and amortization	23,710	13,098	14,551
Share-based compensation	1,100	4,646	34
Impairment of investment	917	—	—
Unrealized (gain) loss on commodity derivatives	(7,149)	3,637	(8,668)
Interest expense, net	1,269	5,219	3,814
Income tax provision (benefit)	12,111	(108)	11,756
EBITDAX	$63,201	$30,351	$44,887
EBITDAX per diluted share	$ 3.03	$ 2.71	$ 4.66

Finding and Development Costs

Drill-bit finding and development costs are calculated by dividing the sum of exploration costs and development costs for the year, by the total of reserve extensions and discoveries for the year.

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

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

We believe that providing the above measures of finding and development cost is useful to assist an evaluation of how much it costs the Company, on a per Mcfe basis, to add proved reserves. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table reflects the reconciliation of our estimated finding and development costs for the year ended December 31, 2008 to the information required by paragraphs 11 and 21 of Statement of Financial Accounting Standard No. 69:

Cost summary (in thousands)	
Property acquisition costs	
Unproved properties	$ 2,695
Proved properties	12,189
Exploration costs	5,007
Development costs(1)	84,193
Total costs incurred	$104,084
Future development costs (in thousands)	
2007	$191,738
2008	201,259
Change in future development costs	$ 9,521
Reserve summary (MMcfe)	
Balance — December 31, 2007	180,400
Extensions and discoveries	42,249
Purchases of minerals in place	7,711
Production	(8,755)
Revisions to previous estimates	(10,537)
Balance — December 31, 2008	211,068
Finding and development costs ($/Mcfe)	
Drill-bit finding and development cost	$ 2.11
All-in finding and development cost, including revisions	$ 2.64
All-in finding and development costs, including revisions and change in future development costs	$ 2.88

(1) Includes $3.5 million in non-cash asset retirement obligations recorded in 2008.

2008 Production Replacement

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

We use production replacement ratios as an indicator of our 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 time of discoveries and property acquisitions. In addition, since these ratios do not incorporate the cost or time of future production of new reserves, they should not be used as a measure of value creation.

Production replaced from all sources is calculated by dividing net proved reserve additions of 39.4 Bcfe (the sum of extensions and discoveries, purchases and revisions) by production of 8.8 Bcfe.

Production replaced from drilling alone is calculated by dividing extensions and discoveries of 42.2 Bcfe by production of 8.8 Bcfe.

Reserve summary (MMcfe)	
Balance — December 31, 2007	180,400
Extensions and discoveries	42,249
Purchases of minerals in place	7,711
Production	(8,755)
Revisions to previous estimates	(10,537)
Balance — December 31, 2008	211,068
Production replacement	
Production replaced from all sources	450%
Production replaced from drilling alone	483%

Corporate Data

BOARD OF DIRECTORS

BRYAN H. LAWRENCE
Chairman of the Board of Directors

J. ROSS CRAFT
President, Chief Executive Officer and Director

JAMES H. BRANDI[1][2]
Director

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

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

CHRISTOPHER J. WHYTE[1]
Director

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

EXECUTIVE OFFICERS

J. ROSS CRAFT
President and Chief Executive Officer

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

GLENN W. REED
Vice President – Operations

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

INDEPENDENT ACCOUNTANTS
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Dallas, Texas

CORPORATE COUNSEL
Thompson & Knight LLP
Dallas, Texas

TRANSFER AGENT AND REGISTRAR
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Plaza Level
New York, New York 10038
800.937.5449

WEBSITE
www.approachresources.com

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

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