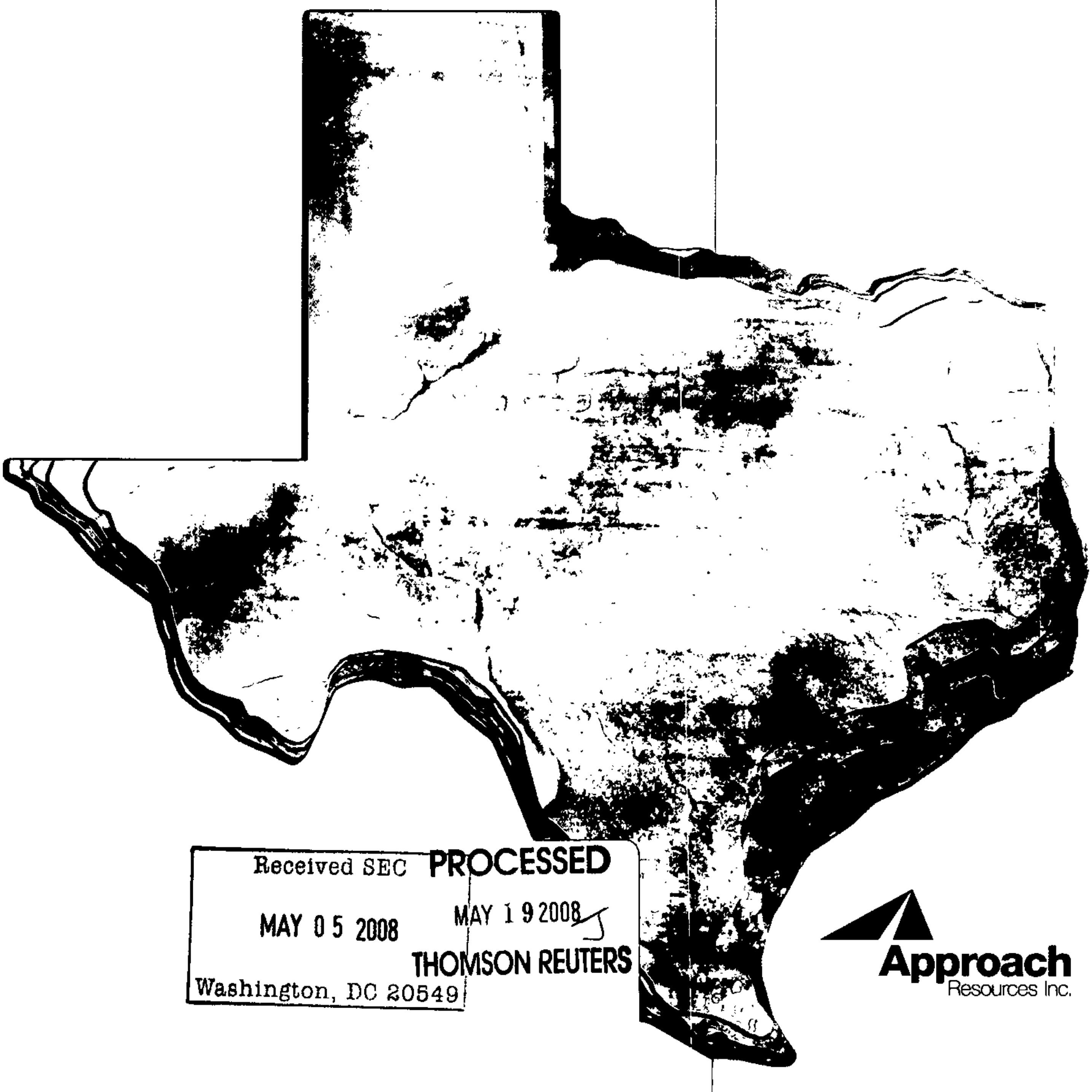
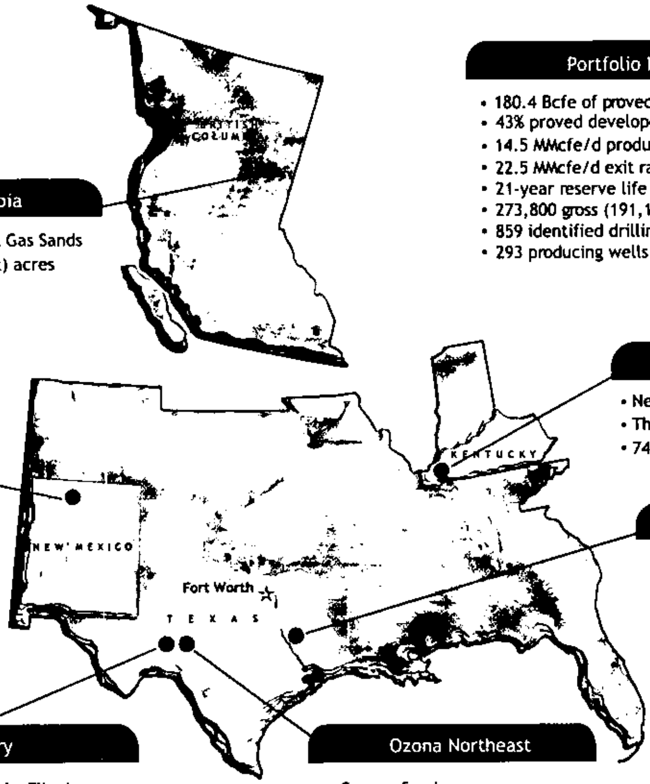
APPROACH RESOURCES INC.

ANNUAL REPORT 2007



Approach
Resources Inc.

Areas of Operation



Portfolio Highlights[1]

- 180.4 Bcfe of proved reserves
- 43% proved developed, 89% natural gas
- 14.5 MMcfe/d production in 2007
- 22.5 MMcfe/d exit rate at March 31, 2008
- 21-year reserve life index
- 273,800 gross (191,182 net) acres
- 859 identified drilling locations
- 293 producing wells

British Columbia

- Triassic Shale and Tight Gas Sands
- 32,700 gross (7,425 net) acres

Boomerang

- New Albany Shale
- Thermogenic gas
- 74,000 gross (44,400 net) acres

El Vado East

- Mancos Shale
- 90,300 gross (81,000 net) acres

North Bald Prairie

- Cotton Valley Sands, Bossier, Cotton Valley Lime
- 21.4 Bcfe of proved reserves
- 10,300 gross (4,850 net) acres
- 61 identified locations

Cinco Terry

- Wolfcamp, Canyon Sands, Ellenburger
- 18.3 Bcfe of proved reserves
- 21,900 gross (9,507 net) acres
- 119 identified locations

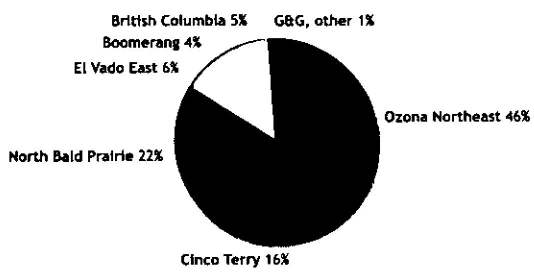
Ozona Northeast

- Canyon Sands
- 140.7 Bcfe of proved reserves
- 44,600 gross (44,000 net) acres
- 679 identified locations

(1) As of December 31, 2007 unless otherwise noted.

Capital Budget and Key Projects

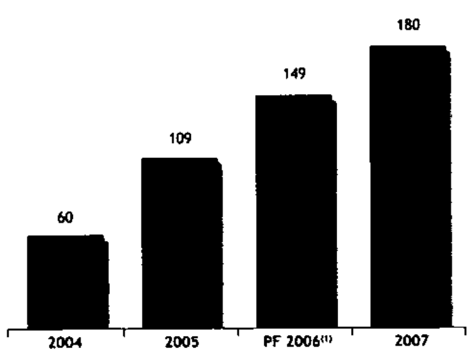
2008 Capital Budget



Total: $64.3mm

Proved Reserve Growth

Proved Reserves (Bcfe)



(1) Pro forma for the acquisition of the 30% working interest in Ozona Northeast that we did not already own, as if the acquisition occurred on January 1, 2006.

Financial and Operating Data

($ thousands, except per unit metrics)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Pro Forma Year Ended December 31, 2007[1]	Pro Forma Year Ended December 31, 2006[1]
Revenues (in thousands):				
Gas	$ 33,497	$ 41,851	$ 45,330	$ 59,417
Oil	5,617	4,821	6,955	6,813
Total oil and gas sales	39,114	46,672	52,285	66,230
Realized gain on commodity derivatives	4,732	6,222	4,732	6,222
Total oil and gas sales including derivative impact	$ 43,846	$ 52,894	$ 57,017	$ 72,452
Production:				
Gas (MMcf)	4,801	6,282	6,467	8,927
Oil (MBbl)	84	77	105	109
Total (MMcfe)	5,305	6,744	7,095	9,580
Average prices:				
Gas, per Mcf	$ 6.98	$ 6.66	$ 7.01	$ 6.66
Oil, per Bbl	66.87	62.65	66.52	62.65
Total, per Mcfe	7.37	6.92	7.37	6.91
Realized gain on commodity derivatives, per Mcfe	0.89	0.92	0.67	0.65
Total per Mcfe including derivative impact	8.26	7.84	8.04	7.56
Costs and expenses (per Mcfe):				
Lease operating expenses	$ 0.72	$ 0.58	$ 0.72	$ 0.57
Severance and production taxes	$ 0.31	$ 0.26	$ 0.31	$ 0.26
Depletion, depreciation and amortization	$ 2.47	$ 2.16	$ 2.41	$ 2.19
Exploration and impairment	$ 0.22	$ 0.32	$ 0.16	$ 0.23
General and administrative	$ 2.39	$ 0.36	$ 1.84	$ 0.29

(1) Gives effect to our acquisition of the 30% working interest in Ozona Northeast that we did not already own, as if the acquisition had occurred on January 1, 2006.

Stockholders' Letter

April 25, 2008

Dear Fellow Stockholders,

Last year provided us with several exciting opportunities as we continued to grow the value of your company. We began the year by expanding our acreage portfolio to include two exploratory prospects, one in British Columbia targeting Montney tight gas sands and the Doig Shale, and one in Northern New Mexico targeting the Mancos Shale. More importantly, during 2007 we accelerated our Canyon and Ellenburger development drilling program in our Cinco Terry project in West Texas, and entered into a joint drilling venture with EnCana Oil & Gas (USA) to develop the North Bald Prairie field in East Texas, which targets the Cotton Valley Lime, Bossier Sands and Cotton Valley Sands. We added 37.9 Bcfe of proved reserves in Cinco Terry and North Bald Prairie in 2007. Our acreage portfolio currently covers 283,282 gross and 196,081 net acres, of which 166,984 is net undeveloped acreage.

In July 2007, we filed a registration statement with the SEC for an initial public offering of our common stock. Our registration statement was declared effective on November 7, 2007, and we began trading on NASDAQ the next day under the ticker "AREX." We used the proceeds to retire $51.1 million of our revolving credit facility and repurchase 2,021,148 shares of common stock from the selling stockholder in our IPO, as part of the acquisition of the selling stockholder's 30% working interest in Ozona Northeast.

At December 31, 2007, our total proved reserves were 180.4 Bcfe, composed of 89% natural gas and 11% oil, condensate and natural gas liquids. This represented a 71% increase from year-end 2006 reserves of 105.4 Bcfe. Giving effect to the acquisition of the 30% Ozona Northeast working interest, we increased proved reserves through the drill bit 21% from 148.8 Bcfe at December 31, 2006. We replaced 714% of 2007 net production through extensions and discoveries. Including the Ozona Northeast working interest acquisition, we replaced 1,514% of 2007 net production volumes.

The bulk of our capital expenditures for 2007 went to the drilling and completing of 46 Canyon wells in Ozona Northeast, our legacy asset. Since our first well in Ozona Northeast in 2004, we have drilled 285 successful wells out of 303 total wells drilled for a 94% success rate. For 2008, we have allocated $29.5 million to Ozona Northeast to drill and complete approximately 44 wells. Also, we are currently reprocessing 3-D seismic shot over our Ozona Northeast field. The results from the interpretation of the seismic data should enable us to identify the net sand channels in this field with even more precision and efficiency than in the past.

Our Cinco Terry project continues to exceed our expectations. We originally identified Cinco Terry as a Canyon Sands tight gas development play. As we continue to study the data from the wells in Cinco Terry, we believe that this field has substantial upside potential in the Ellenburger formation as well as Canyon and Wolfcamp up the hole. Our 2008 plans in Cinco Terry include drilling 24 wells and strategically expanding our acreage in the area. We recently acquired an additional 9,482 gross (4,899 net) acres in the northwest portion of our Cinco Terry project, bringing our total holdings in Cinco Terry to 31,382 gross (14,406 net) acres.

We believe our North Bald Prairie project in the East Texas Cotton Valley/Bossier trend is a high-quality development play. In 2007, we drilled four vertical test wells and one additional well in February 2008. All five wells were completed as producers in the Cotton Valley Sand, Bossier Sand or Cotton Valley Lime, with average initial production rates of 1.6 MMcf/d per well (gross). We expect to drill an additional 12 wells in 2008.

In 2008, we plan to continue to efficiently develop our West Texas and East Texas properties and exploit our significant reserve potential there. We have identified 859 drilling locations in our core development drilling projects: 679 in Ozona Northeast, 119 in Cinco Terry and 61 in North Bald Prairie. We also plan to test the prospectivity of our emerging plays in British Columbia, Northern New Mexico and Southwest Kentucky. Finally, we will continue to evaluate acquisition and joint venture opportunities that emphasize our management and technical team's expertise in developing unconventional natural gas reservoirs, complement our acreage portfolio and increase stockholder value.

I would like to thank our employees, business partners and fellow stockholders for a successful year that transformed your company. I am grateful for your confidence in and support of AREX.

Sincerely,

J. Ross Craft
Director,
President and Chief Executive Officer

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, 2007, which was filed with the Securities and Exchange Commission on March 28, 2008.

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, 2007

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 *(State or other jurisdiction of incorporation or organization)*	**51-0424817** *(I.R.S. employer identification number)*
One Ridgmar Centre **6500 W. Freeway, Suite 800** **Fort Worth, Texas** *(Address of principal executive office)*	**76116** *(Zip code)*

(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 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 registrant was not a publicly reporting entity as of the last business day of its most recently completed second quarter and, therefore, cannot calculate the aggregate market value of its voting and non-voting common equity held by non-affiliates as of such date. The aggregate market value of the registrant's common voting and non-voting common equity held by non-affiliates as of December 31, 2007 (based on the closing price on the Nasdaq Global Market on such date) was $117.5 million. The number of shares of the registrant's common stock, par value $0.01, outstanding as of March 27, 2008 was 20,622,746.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2008 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 natural gas and oil 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:

- our business strategy,
- estimated quantities of gas and oil reserves,
- uncertainty of commodity prices in oil and gas,
- our financial position,
- our cash flow and liquidity,
- replacing our gas and oil reserves,
- our inability to retain and attract key personnel,
- uncertainty regarding our future operating results,
- uncertainties in exploring for and producing gas and oil,
- availability of drilling and production equipment and field service providers,
- 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 gas and oil,
- 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 onshore in the United States and British Columbia. We focus our growth efforts primarily on finding and developing natural gas reserves in known tight sands and shale gas areas and have assembled leasehold interests aggregating approximately 273,800 gross (191,182 net) acres. 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 substantially all of our 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 and Canyon Sands)
- Cinco Terry (Wolfcamp, Canyon Sands, Ellenburger)

East Texas

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

Northeast British Columbia

- Montney tight gas and Doig Shale

North New Mexico

- El Vado East (Mancos Shale)

Southwest Kentucky

- Boomerang (New Albany Shale)

At December 31, 2007, we owned working interests in 293 producing oil and gas wells, had estimated proved reserves of approximately 180.4 Bcfe and were producing 20.2 MMcfe/d (based on production for the month of December 2007). Our average daily net production for the months of January and February 2008 was 20.3 MMcfe/d and 22.4 MMcfe/d, respectively.

As of December 31, 2007, all of our proved reserves and production were located in the Ozona Northeast and Cinco Terry in West Texas and in North Bald Prairie in East Texas. At year end 2007, our proved reserves were 89% natural gas, 43% proved developed and had a reserve life index of 21 years (based on estimated 2008 production of 8.3 Bcfe). In addition to our producing wells, we have identified 859 total drilling locations in Ozona Northeast, Cinco Terry and North Bald Prairie at December 31, 2007, of which 265 are proved.

The standardized measure of discounted future net cash flows of our proved reserves at December 31, 2007 was $216.0 million, and our PV-10 was $345.7 million. PV-10 may be considered a non-GAAP financial measure as defined by the Securities and Exchange Commission (the "SEC") 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 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.

Approach was incorporated in 2002. We farmed into the Ozona Northeast field in 2004 and since that time have added 180.4 Bcfe of proved reserves through our own drilling efforts in Ozona Northeast, Cinco Terry and North Bald Prairie. 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.

Initial public offering and Neo Canyon acquisition

In November 2007 we completed an initial public offering ("IPO") of 8.8 million shares of our common stock. In connection with the IPO, we acquired the 30% working interest in Ozona Northeast (the "Neo Canyon interest") that we did not already own from Neo Canyon Exploration, L.P. Neo Canyon received shares of our common stock for the Neo Canyon interest and was the sole selling stockholder in our IPO. See Note 2 to our consolidated financial statements.

Strategy

Our objective is to build 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 developmental properties, (2) exploring and exploiting our undeveloped properties, (3) completing strategic acquisitions and (4) maintaining financial flexibility. 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 859 drilling locations. We believe we have the technical expertise and operational experience to maximize the value of these properties. From 2004 through 2007, we drilled over 300 wells in our Ozona Northeast and Cinco Terry fields in West Texas, making us one of the 11 most active drillers in West Texas and the second most active driller in the Canyon Sands during that time period.

- *Exploit our undeveloped gas and oil opportunities.* We have over 242,000 gross acres of undeveloped tight gas and shale gas and oil inventory to explore and produce. We seek to add proved reserves and production from these properties through advanced technologies, including horizontal drilling and advanced fracing and completion techniques.

- *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 (44,600 gross and 44,000 net acres and 140.7 Bcfe of proved reserves), North Bald Prairie (10,300 gross and 4,850 net acres and 21.4 Bcfe of proved reserves) and Northeast British Columbia (32,700 gross and 7,425 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 an acquisition of the property itself could cost.

- *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.

- *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 are the operator of substantially all of our producing properties and plan to continue to operate substantially all 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, 2007, we had no long-term debt outstanding and $75 million available for borrowings under our revolving credit facility, providing us with significant financial flexibility to pursue our business strategy. We currently have $13.8 million in long-term debt outstanding under our credit facility.

Oil and gas properties and operations

West Texas

Ozona Northeast (Canyon Sands)

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 44,600 gross (44,000 net) acres. Beginning with our first well in February 2004, through December 31, 2007, we have drilled 285 successful wells out of 303 total wells drilled, for a 94% success rate. As of December 31, 2007, we had estimated proved reserves of 140.7 Bcfe from Ozona Northeast. We have a 100% working interest and a net revenue interest of approximately 80% in Ozona Northeast. Average daily production for January and February 2008 from Ozona Northeast was 17.6 MMcfe/d (net) and 17.3 MMcfe/d (net), respectively. We have identified 679 additional drilling locations in Ozona Northeast as of December 31, 2007, of which 196 are proved. We own and operate 65 miles of gas gathering lines in the area that transport our gas to several regional pipeline systems.

Cinco Terry (Wolfcamp, Canyon Sands and Ellenburger)

Since late 2005, we have leased and acquired options to lease 21,900 gross (9,507 net) acres in our Cinco Terry project, two miles northwest of the Ozona Northeast border, to evaluate the Wolfcamp, Canyon and Ellenburger formations. As of December 31, 2007, we had drilled and completed six Canyon wells and seven Ellenburger wells and had estimated proved reserves of 18.3 Bcfe in Cinco Terry. We have approximately a 50% working interest and 39% net revenue interest in our Cinco Terry project. Average daily production for January and February 2008 from Cinco Terry was 2.3 MMcfe/d (net) and 3.6 MMcfe/d (net), respectively. We have identified 119 additional drilling locations in our Cinco Terry acreage as of December 31, 2007, of which 36 are proved. We own and operate seven miles of gas gathering lines in the area that transport our gas to several regional pipeline systems.

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 10,300 gross (4,850 net) acres. We began drilling operations on the initial North Bald Prairie well in August 2007. As of February 29, 2008, we had drilled and completed all five wells. We have a 50% working interest and approximately a 40% net revenue interest in our North Bald Prairie project. Under our carry and earning agreement with EnCana, we drilled and we operate the initial five wells in North Bald Prairie. However, EnCana has the right to elect to operate the initial five wells. Either party may propose to drill and operate future wells under the joint operating agreement between us and EnCana. Average daily production for January and February 2008 from North Bald Prairie was 0.5 MMcfe/d (net) and 1.5 MMcfe/d (net), respectively. 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 61 potential drilling locations in North Bald Prairie as of December 31, 2007, of which 33 are proved.

Northeast British Columbia

Montney Tight Gas and Doig Shale

In August 2007, we acquired a non-operating, working interest ranging from 12.3% 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 32,700 gross (7,425 net) acres. Our primary targets are Triassic-aged tight gas and shale gas. We participated in one (0.25 net) vertical Montney Sand exploratory well in 2007. In January 2008, we participated in one (0.25 net) vertical exploratory well. The Canadian operator plans to frac and complete both the Montney Sand and Doig Shale zones. A third (0.25 net) well, a horizontal Montney Sand development well, has been drilled, cased and is waiting on completion. Royalties are variable month to month depending on price, volume and product. Royalties for our current prospects range from a low of less than 10% at low volumes and low prices to a high of approximately 27% at more substantial prices and volumes.

North New Mexico

El Vado East (Mancos Shale)

Our El Vado East prospect is a 90,300 gross (81,000 net) acre Mancos Shale play located in the Chama Basin in North New Mexico in proximity to several productive fields, including the Puerto Chiquito West and Puerto Chiquito East fields and the Boulder field, 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 expect that in the second quarter of 2008 we will spud the first of eight vertical test wells to be drilled in El Vado East before April 2009. We have a 90% working interest and a net revenue interest of approximately 72% in our El Vado East prospect.

Southwest Kentucky

Boomerang (New Albany Shale)

Our Boomerang prospect is a 74,000 gross (44,400 net) acre New Albany Shale play located in Southwest Kentucky in the Illinois Basin. In the first quarter of 2007, we drilled three vertical test wells and analyzed cores from these wells. We currently are formulating a development plan for this prospect. We have a 60% working interest and a net revenue interest of approximately 50% in our Boomerang prospect.

Natural gas and oil reserves

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2007 and 2006. See Note 12 "Disclosures about Oil and Gas Producing Activities (unaudited)" to our consolidated financial statements for additional information. The company's estimated total proved reserves of natural gas and oil as of December 31, 2007 were 180.4 Bcfe. The 2007 reserves are composed of 89% natural gas and 11% oil, condensate and natural gas liquids. The proved developed portion of total proved reserves at year end 2007 was 43%. The company's reserve estimates and PV-10 (defined below) 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, 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
December 31, 2006			
Ozona Northeast			
Proved Developed	50,652	403	53,066
Proved Undeveloped	47,339	524	50,485
Total Proved	97,991	927	103,551
Cinco Terry			
Proved Developed	352	94	914
Proved Undeveloped	314	101	922
Total Proved	666	195	1,836
Total			
Proved Developed	51,004	497	53,980
Proved Undeveloped	47,653	625	51,407
Total Proved	98,657	1,122	105,387

Pro forma for the acquisition of the Neo Canyon interest, our proved reserves at December 31, 2006 were 148.8 Bcfe.

The standardized measure of discounted future net cash flows for our proved reserves at December 31, 2007 was $216.0 million.

The present value of our proved reserves, discounted at 10% (PV-10), was estimated at $345.7 million, based on year end weighted average prices of $8.10 per Mcf for natural gas, $93.30 per Bbl for oil and $60.09 per Bbl for natural gas liquids. 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.

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 estimated proved 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 gas and oil 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,	
	2007	2006
	(In thousands)	
PV-10	$ 345,656	$ 128,433
Less income taxes:		
Undiscounted future income taxes	(285,384)	(109,784)
10% discount factor	155,688	59,228
Future discounted income taxes	(129,696)	(50,556)
Standardized measure of discounted future net cash flows	$ 215,960	$ 77,877

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 presents certain information with respect to natural gas and oil production attributable to all our interests in all of our operating areas, the revenue derived from the sale of such production, average sales prices received and average production costs during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
Net Production:			
Natural gas (MMcf)	4,801	6,282	4,668
Oil and condensate (MBbls)	84	77	57
Total (MMcfe)	5,305	6,744	5,012
Average Net Daily Production:			
Total (MMcfe)	15	18	14
Average Realized Sales Price per Unit (without the effects of commodity derivatives):			
Natural gas (per Mcf)	$ 6.98	$ 6.66	$ 8.59
Oil and condensate (per Bbl)	66.87	62.65	55.54
Average realized price (per Mcfe)	$ 7.37	$ 6.92	$ 8.63
Average Realized Sales Price per Unit (with the effects of commodity derivatives):			
Natural gas (per Mcf)	$ 7.96	$ 7.65	$ 7.96
Oil and condensate (per Bbl)	66.87	62.65	55.54
Average realized price (per Mcfe)	$ 8.26	$ 7.84	$ 8.05
Expenses (per Mcfe)			
Lease operating	$ 0.72	$ 0.58	$ 0.58
Severance and production taxes	0.31	0.26	0.39
Exploration	0.17	0.24	0.15
Impairment of non-producing properties	0.05	0.08	—
General and administrative	2.39	0.36	0.53
Depletion, depreciation and amortization	2.47	2.16	1.60

Productive wells

The following table sets forth the number of productive gas and oil wells in which we owned a working interest at December 31, 2007.

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	278.0	264.5	1.0	1.0	279.0	265.5
Cinco Terry	6.0	3.0	6.0	3.0	12.0	6.0
North Bald Prairie	2.0	1.0	—	—	2.0	1.0
Total Productive Wells	286.0	268.5	7.0	4.0	293.0	272.5

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2007.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	27,500	26,900	17,100	17,100	44,600	44,000
Cinco Terry	1,900	982	20,000	8,525	21,900	9,507
North Bald Prairie	2,100	1,050	8,200	3,800	10,300	4,850
El Vado East	—	—	90,300	81,000	90,300	81,000
Boomerang	—	—	74,000	44,400	74,000	44,400
Northeast British Columbia	—	—	32,700	7,425	32,700	7,425
Total	31,500	28,932	242,300	162,250	273,800	191,182

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2007 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Ozona Northeast	14,000	13,000	3,000	2,200	—	—
Cinco Terry	11,600	3,700	1,800	1,100	6,100	3,100
North Bald Prairie(1)	2,400	2,300	5,600	5,400	200	200
El Vado East(2)	—	—	90,300	81,000	—	—
Boomerang(3)	—	—	—	—	6,400	3,800
Northeast British Columbia	7,700	1,200	—	—	22,800	5,700
Total	35,700	20,200	100,700	89,700	35,500	12,800

(1) Assumes the exercise of options to extend current primary terms by three additional years (through November 2008) on approximately 7,700 gross (2,000 net) acres for $125 to $250 per net acre.

(2) We have an eight-well drilling commitment during the primary term, which expires in April 2009. If we meet this requirement, 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.

(3) Assumes the exercise of options to extend the current primary terms by three to five additional years (beginning July 2009 through September 2010) on approximately 67,600 gross (41,000 net) acres for $30 to $45 per net acre.

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,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	51.0	46.0	81.0	53.3	115.0	74.8
Non-productive	5.0	4.0	6.0	4.2	7.0	4.3
Exploratory:						
Productive	—	—	2.0	1.0	1.0	0.5
Non-productive	1.0	0.7	—	—	2.0	1.0
Total:						
Productive	51.0	46.0	83.0	54.3	116.0	75.3
Non-productive	6.0	4.7	6.0	4.2	9.0	5.3

Wells drilled in 2007 are pro forma for the acquisition of 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 demand for, gas and oil. The price we receive for our gas and oil production depends on numerous factors beyond our control, including seasonality, the conditions of the United States economy, particularly in the manufacturing sector, political conditions in other oil and gas producing countries, the extent of domestic production and imports of gas and oil, the proximity and capacity of gas pipelines and other transportation facilities, demand for oil and gas, the marketing of competitive fuels and the effects of state and federal 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, 2007, Ozona Pipeline, an affiliate of Neo Canyon Exploration, L.P., the selling stockholder in our IPO, was our most significant purchaser, accounting for approximately 85.9% of our total 2007 gas and oil 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 gas and oil 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 "change in fair value of 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 gas and oil 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. To date, the 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.

The 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 and the regulation of the spacing, 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

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

- require the acquisition of various permits before drilling 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, imposes 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 results of operations and financial position.

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.

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.

Other 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.

Employees

At March 14, 2008, we had 25 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 materially adverse effect on our financial position or 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 the Audit Committee and the Compensation and Nominating Committee, and the 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 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

Gas and oil 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 gas and oil. 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 gas and oil fluctuate widely in response to relatively minor changes in the supply and demand for gas and oil, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of gas and oil,
- 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, including the current conflicts in the Middle East and conditions in South America and Russia,
- 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,
- technological advances affecting gas and oil consumption,
- overall United States and global economic conditions, and
- price and availability of alternative fuels.

Further, gas prices and oil prices do not necessarily fluctuate in direct relationship to each other. Because more than 89% of our estimated proved reserves as of December 31, 2007 were gas reserves, our financial results are more sensitive to movements in gas prices. In the past, the price of gas has been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2007, the NYMEX gas spot price ranged from a high of $8.64 per MMBtu to a low of $5.38 per MMBtu. The NYMEX gas spot price at December 31, 2007 was $7.47 per MMBtu. At March 19, 2008, the NYMEX gas spot price was $9.02 per MMBtu.

The results of higher investment in the exploration for and production of gas and other factors may cause the price of gas to drop. Lower gas and oil prices may not only cause our revenues to decrease but also may reduce the amount of gas and oil that we can produce economically. Substantial decreases in gas and oil 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 financial condition, results of operations and cash flow.

Drilling and exploring for, and producing, gas and oil 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 gas and oil prices,
- limitations in the market for gas and oil,
- surface access restrictions,
- title problems,
- compliance with governmental regulations, and
- mechanical difficulties.

Our decisions to purchase, explore, develop and exploit 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 predrilling expenditures than traditional drilling strategies.

In addition, higher gas and oil prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increasing costs for, such drilling equipment, services and personnel. Such shortages could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues.

Currently, all of our producing properties are located in four counties in Texas, and our proved reserves are primarily attributable to one field, 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 one field in that area, Ozona Northeast. 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, 2007, 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 2008 and 2015. Options covering approximately 11,600 gross acres in our Cinco Terry project are scheduled to expire before June 1, 2008. 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. For the year ended December 31, 2007, we recorded an impairment expense of $267,000 related to the write-off of 2,284 acres in the northwest portion of Ozona Northeast. This acreage is due to expire in April 2008 and we plan to let the acreage expire at that time.

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 gas and oil.

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 gas and oil 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 gas and oil reserves, our reserves and production will decline.

Our future gas and oil 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 gas and oil 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 gas and oil 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 gas and oil reserve information included in this report represents estimates. Petroleum engineering is a subjective process of estimating underground accumulations of gas and oil that cannot be measured in an exact manner. Estimates of economically recoverable gas and oil 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 gas and oil 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 gas and oil that are ultimately recovered,

- the production and operating costs incurred,
- the amount and timing of future development expenditures, and
- future gas and oil prices.

As of December 31, 2007, approximately 57% of our proved reserves were proved undeveloped. Estimates of proved undeveloped reserves are even less reliable than estimates of proved developed reserves.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows 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 discounted future net cash flows included in this report should not be considered as the current market value of the estimated gas and oil reserves attributable to our properties. As required by the SEC the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the measurement (December 31, 2007), while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

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

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

You should not assume that the present value of future net revenues from our proved reserves referred to in this report is the current market value of our estimated gas and oil reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If gas prices decline by $1.00 per Mcf from $8.10 per Mcf to $7.10 per Mcf, then our PV-10 as of December 31, 2007 would decrease from $345.7 million to $288.5 million. The average market price received for our natural gas production for the month of December 31, 2007, after basis and Btu adjustments, was $7.20 per Mcf.

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. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. As a result of historically strong prices of gas, the demand for oilfield and drilling services has risen, and the costs of these services may increase. We are particularly sensitive to higher rig costs and drilling rig availability, as we presently have three rigs under contract, two of which are on a well-to-well basis. 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 gas and oil 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 2007, Ozona Pipeline Energy Company, which we refer to as Ozona Pipeline, and Conoco Phillips accounted for approximately 85.9% and 12.1%, respectively, of our total gas and oil sales excluding realized commodity derivative settlements. To the extent that Ozona Pipeline or Conoco Phillips 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. Ozona Pipeline's or Conoco Phillips' 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 Senior Vice President — 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 controlling interest in our company, whose interests may differ from your interests and who will be able to determine the outcome of matters voted upon by our stockholders.

At December 31, 2007, 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 45.6% of our outstanding common stock in the aggregate. In addition, one Yorktown representative serves on our board of directors, and our non-Yorktown directors, management team and employees beneficially own or control approximately 11.4% 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 the vote in any election of directors. Yorktown, together with our board and management, also has control over our decisions to enter into significant corporate transactions and, in their capacity as our majority stockholders, these stockholders have the ability to prevent 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, 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 non-employee 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, gas and oil, 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."

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

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

Market conditions, the unavailability of satisfactory gas and oil processing and transportation may hinder our access to gas and oil markets or delay our production. Although currently we control the pipeline operations for a majority of our production in the Ozona Northeast field, we do not have such control in other areas where we expect to conduct operations. The availability of a ready market for our gas and oil production depends on a number of factors, including the demand for and supply of gas and oil and the proximity of reserves to pipelines or trucking and terminal facilities. In addition, the amount of gas and oil 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, 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 gas and oil production from wells or we may be required to shut in gas wells or delay initial production until the necessary gathering and transportation systems are available. Any significant curtailment in gathering system or pipeline capacity, or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition or results of operations.

Environmental liabilities may expose us to significant costs and liabilities.

There is inherent risk of incurring significant environmental costs and liabilities in our gas and oil 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 production or our operations or financial position. 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 gas and oil, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Gas and oil 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 gas and oil 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 implement fully 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 capital budget, which is expected to be approximately $64.3 million for 2008. As of December 31, 2007, approximately 57% 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, 2007, no outstanding borrowings existed under our revolving credit facility. A portion of the proceeds from our initial public offering repaid a portion of the outstanding balance under our revolving credit facility. We currently have $13.8 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 gas and oil production, we enter into gas and oil 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 gas and oil 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 consolidated financial condition, results of operations or cash flows.

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, range of common stock and number of record holders

Our common stock is traded on the Nasdaq Global Market ("Nasdaq") in the United States under the symbol "AREX". Our common stock began trading on Nasdaq on November 8, 2007. Between that date and December 31, 2007, the high and low closing sales prices of our common stock as reported on Nasdaq were $13.41 and $12.30, respectively.

As of March 14, 2008, there were 15 record holders of our common stock.

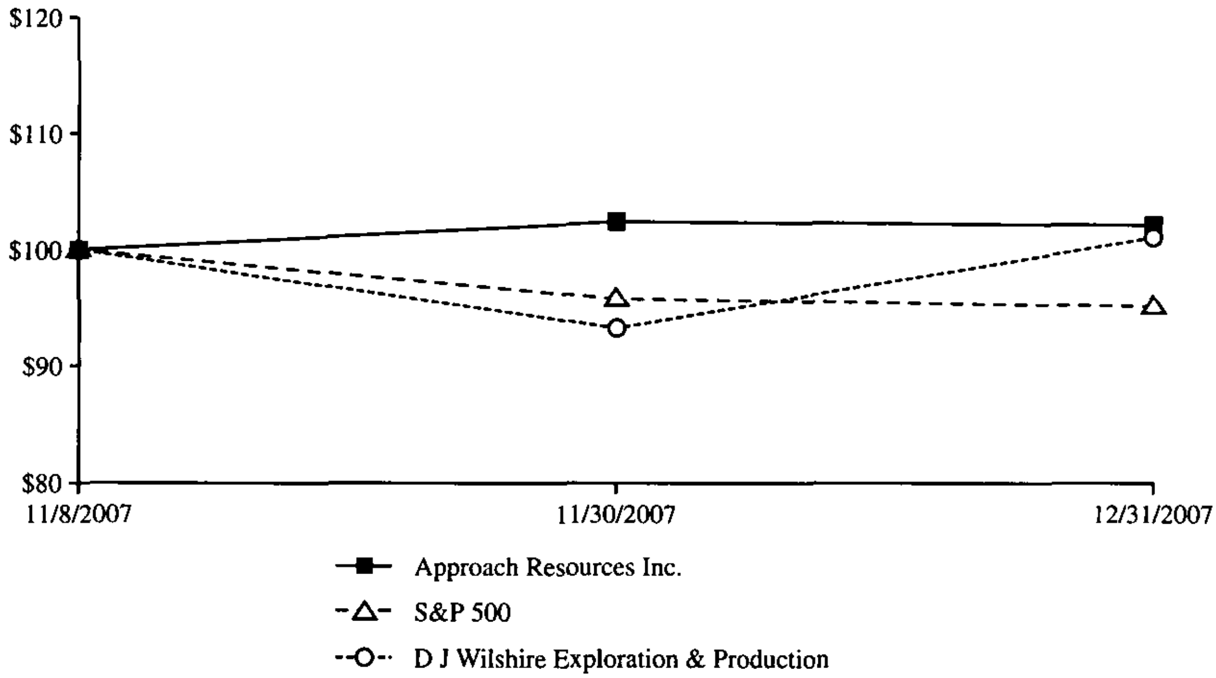
Dividends

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 (the date our common stock trading began on Nasdaq) or October 31, 2007 in the applicable index, through December 31, 2007, 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 (the "Securities Act") or the Securities Exchange Act of 1934 (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 Since November 8, 2007
Among Approach Resources Inc., the Standard & Poor's 500 Index and
the Dow Jones Wilshire Exploration & Production Index



	11/8/2007	11/30/2007	12/31/2007
Approach Resources Inc.	$ 100.00	$ 102.46	$ 102.14
S&P 500	100.00	95.82	95.15
D J Wilshire Exploration & Production	100.00	93.31	101.09

Recent sales of unregistered securities

In the three years preceding the filing of this report on Form 10-K, we issued and sold the following securities that were not registered under the Securities Act:

1. On August 16, 2004, we issued 3,390,000 (split adjusted) shares of our common stock to Yorktown Energy Partners V, L.P. and certain of our employees in consideration of $11,300,000, $1,202,500 of which was evidenced by full recourse promissory notes secured by pledge of the securities purchased. These shares were issued in a transaction exempt from the registration requirements of the Securities Act under Section 4(2) of the Securities Act.

2. On August 30, 2004, we issued 375,000 (split adjusted) shares of our common stock to certain of our employees in consideration of $1,250,000 evidenced by full recourse promissory notes secured by pledge of the securities purchased. These shares were issued in a transaction exempt from the registration requirements of the Securities Act under Section 4(2) of the Securities Act.

3. On March 14, 2007, we issued 63,750 (split adjusted) shares of restricted common stock to J. Curtis Henderson, our Executive Vice President and General Counsel, in connection with Mr. Henderson's hiring. These shares were issued in a transaction exempt from the registration requirements of the Securities Act pursuant to Rule 701 under the Securities Act.

4. On June 25, 2007, Approach Oil & Gas Inc. ("AOG") issued convertible promissory notes to each of Yorktown Energy Partners VII, L.P. and Lubar Equity Fund, LLC in the aggregate amount of $20,000,000. The notes and accrued interest of approximately $548,000 automatically converted into 1,841,262 (split adjusted) shares of our common stock upon the completion of our IPO on November 14, 2007. The number of shares of 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 underwriting discounts. These shares issued upon the conversion of these notes were issued in a transaction exempt from the registration requirements of the Securities Act under Section 4(2) of the Securities Act.

5. On July 20, 2007, we issued 72,114 (split adjusted) shares of common stock pursuant to the exercise of stock options held by a former executive officer at an exercise price of $3.33 per share. The issuance of these shares was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

6. On November 14, 2007, we completed the IPO of our common stock pursuant to our registration statement on Form S-1 (File 333-144512) declared effective by the SEC on November 8, 2007. The underwriters for the offering were J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, KeyBanc Capital Markets Inc. and Tudor, Pickering, Holt & Co. Securities, Inc. Pursuant to the registration statement, we registered the offer and sale of 8,816,667 shares of our $0.01 par value common stock, which included 2,061,290 shares sold by the selling stockholder and 1,150,000 shares subject to an option granted to the underwriters by us to cover over-allotments. The underwriters exercised their over-allotment option on November 14, 2007. The sale of the shares in our IPO closed on November 14, 2007 and the sale of the shares covered by the over-allotment option closed on November 16, 2007. Our IPO terminated upon completion of the closing.

   The gross proceeds of our IPO, including the gross proceeds from over-allotment option, based on the IPO price of $12.00 per share, were approximately $79.2 million, which resulted in (a) net proceeds to the Company of $73.6 million after deducting underwriter discounts and commissions of approximately $5.6 million, and (b) net proceeds to the selling stockholder of approximately $23.0 million. We did not receive any proceeds from the sale of the shares by the selling stockholder. We also paid for legal fees incurred by the selling stockholder. Other than for such fees, no fees or expenses have been paid, directly or indirectly, to any officer, director or 10% stockholder or other affiliate. The net proceeds from our IPO were used to (a) repay a portion of our revolving credit facility in November 2007 totaling $51.1 million and (b) repurchase 2,021,148 shares of our common stock held by the selling stockholder for approximately $22.5 million.

Issuer repurchases of equity securities

Except as discussed above under "Recent sales of unregistered securities" with respect to the repurchase of 2,021,148 shares of our common stock from the selling stockholder in November 2007 for approximately $22.5 million, we made no repurchases of our common stock during the year ended December 31, 2007.

Item 6. *Selected Financial Data.*

The following table sets forth selected financial information for the five years ended December 31, 2007. 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 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,				
	2007	2006	2005	2004	2003
	(In thousands, except per share data)				
Operating results data					
Revenues:					
Oil and gas sales	$ 39,114	$ 46,672	$ 43,264	$ 5,682	$ —
Expenses:					
Lease operating expense	3,815	3,889	2,910	179	—
Severance and production taxes	1,659	1,736	1,975	407	—
Exploration	883	1,640	733	2,396	442
Impairment of non-producing activities	267	558	—	—	—
General and administrative	12,667	2,416	2,659	1,943	1,535
Depletion, depreciation and amortization	13,098	14,551	8,011	1,224	9
Total expenses	32,389	24,790	16,288	6,149	1,986
Operating income (loss)	6,725	21,882	26,976	(467)	(1,986)
Other:					
Interest (expense) income, net	(5,219)	(3,814)	(802)	201	59
Realized gain (loss) on commodity derivatives	4,732	6,222	(2,925)	—	—
Change in fair value of commodity derivatives	(3,637)	8,668	(4,163)	—	—
Income (loss) before (benefit) provision for income taxes	2,601	32,958	19,086	(266)	(1,927)
(Benefit) provision for income taxes	(108)	11,756	7,028	—	—
Net income (loss)	$ 2,709	$ 21,202	$ 12,058	$ (266)	$(1,927)
Earnings (loss) per share:					
Basic	$ 0.25	$ 2.26	$ 1.32	$ (0.05)	$ (1.15)
Diluted	$ 0.24	$ 2.20	$ 1.32	$ (0.05)	$ (1.15)
Statement of cash flows data					
Net cash provided (used) by:					
Operating activities	$ 30,746	$ 34,305	$ 40,588	$ 4,528	$(2,391)
Investing activities	(52,940)	(59,384)	(72,224)	(26,859)	(15)
Financing activities	22,062	26,771	32,199	22,474	4,898
Balance sheet data					
Cash	$ 4,785	$ 4,911	$ 3,219	$ 2,656	$ 2,513
Other current assets	12,362	13,200	16,305	6,458	410
Property, equipment, net, successful efforts method	230,478	132,112	88,803	24,223	35
Other assets	1,101	86	89	1,565	—
Total assets	$248,726	$150,309	$108,416	$ 34,902	$ 2,958
Current liabilities	$ 22,017	$ 15,421	$ 32,746	$ 9,827	$ 86
Long-term debt	—	47,619	29,425	100	—
Other long-term debt liabilities	26,890	17,697	6,555	99	—
Stockholders' equity	199,819	69,572	39,690	24,876	2,872
Total liabilities and stockholders' equity	$248,726	$150,309	$108,416	$ 34,902	$ 2,958

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 onshore in the United States and British Columbia. We are focusing our growth efforts primarily on finding and developing natural gas reserves in known tight gas sands and shale areas and have assembled leasehold interests aggregating approximately 273,800 gross (191,182 net) acres. 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 substantially all of our 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 and Canyon Sands)
- Cinco Terry (Wolfcamp, Canyon Sands, Ellenburger)

East Texas

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

Northeast British Columbia

- Montney tight gas and Doig Shale

North New Mexico

- El Vado East (Mancos Shale)

Southwest Kentucky

- Boomerang (New Albany 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, 2007, we owned working interests in 293 producing oil and gas wells, had estimated proved reserves of approximately 180.4 Bcfe and were producing 20.2 MMcfe/d (based on production for the month of December 2007). Our average daily net production for the months of January and February 2008 was 20.3 MMcfe/d and 22.4 MMcfe/d, respectively.

As of December 31, 2007, 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 2007, our proved reserves were 89% natural gas, 43% proved developed and had a reserve life index of 21 years (based on estimated 2008 production of 8.3 Bcfe). In addition to our producing wells, we had identified 859 total drilling locations in Ozona Northeast, Cinco Terry and North Bald Prairie at December 31, 2007.

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, inventory storage levels, gas price differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. 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.

Higher oil and gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services and have caused increases in the costs of those goods and services. To date, the higher sales prices have more than offset the higher drilling and operating costs. Given the inherent volatility of gas prices, which are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions, which generally are lower than the average sales prices received. 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. At the completion of our IPO, we repaid all amounts outstanding under our revolving credit facility plus accrued interest. We believe we have adequate unused borrowing capacity under our revolving credit facility for possible acquisitions, temporary working capital needs and any expansion of our drilling program. Funding for future acquisitions also may require additional sources of financing, which may not be available.

Critical accounting policies and estimates

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

Oil and gas activities

Accounting for oil and gas activities is subject to special, unique rules. We use the successful efforts method for 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
- impairments of properties, if any, are based on the evaluation of the carrying value of properties against their fair value based upon pools of properties grouped by geographical and geological conformity.

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, 2007 proved reserves volumes would have resulted in approximately $1.4 million of additional depletion expense for the year ended December 31, 2007.

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

Derivative instruments and commodity derivative activities

All derivative instruments are recorded on the balance sheet at fair value. We determine the fair value of our derivatives by estimating the present value of future net cash flows expected from those contracts. We compute the estimate by multiplying the notional quantities specified in our contracts by the difference between exchange-quoted forward prices and the strike price specified in our contracts. We then compute the present value of those cash flows using our credit-adjusted risk-free rate under our credit agreement. 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 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 "change in fair value of 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, 2007, we recognized an unrealized loss of $3.6 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2006, we recognized an unrealized gain of $8.7 million from the change in the fair value of commodity derivatives. A 10% increase in the NYMEX floating prices would have resulted in a $2.1 million decrease in the December 31, 2007 fair value recorded on our balance sheet, and a corresponding increase to loss on commodity derivatives in our statement of operations.

Share-based compensation

Prior to January 1, 2006, we accounted for stock option awards granted under our 2003 Stock Option Plan in accordance with the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* and related Interpretations, as permitted by Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"). Share-based employee compensation expense was not recognized in the our consolidated statements of operations prior to January 1, 2006, as all stock option awards granted had an exercise price equal to or greater than the estimated fair market value of the common stock on the date of the grant. As permitted by SFAS No. 123, we reported in the notes to our consolidated financial statements the pro forma disclosures presenting results and earnings (loss) per share as if we had used the fair value recognition provisions of SFAS No. 123. Share-based compensation related to non-employees and modifications of options granted were accounted for based on the fair value of the related stock or options in accordance with SFAS No. 123 and its interpretations.

Effective January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* ("SFAS No. 123(R)"), which requires the measurement and recognition of compensation expense for all share-based payment awards to employees and directors based on estimated fair values. We adopted SFAS No. 123(R) using the modified prospective transition method. In accordance with the modified prospective application provisions of SFAS No. 123(R), compensation cost for the portion of awards that were outstanding as of January 1, 2006, for which the requisite service was not rendered, are recognized as the requisite service is rendered, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R). Additionally, compensation costs for awards granted after January 1, 2006 are recognized over the requisite service period based on the grant-date fair value. In accordance with the modified prospective transition method, our consolidated financial statements for prior periods have not been restated to reflect the impact of SFAS No. 123(R).

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the year ended December 31, 2007. There were no options granted during the years ended December 31, 2006 and 2005:

Expected dividends	—
Expected volatility	68%
Risk-free interest rate	3.9%
Expected life	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. 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 No. 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 have been immaterial to share-based compensation expense for the year ended December 31, 2007.

Recent accounting pronouncements

In March 2008, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 ("SFAS 161"). SFAS 161 amends and expands the disclosure requirements of FASB Statement No. 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 No. 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 No. 141 (revised 2007), *Business Combinations* ("SFAS No. 141(R)"). SFAS No. 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 No. 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 No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51* ("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.

In September 2006, Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* ("SFAS 157"), was issued. SFAS 157 provides guidance for using fair value to measure assets and liabilities. It applies whenever other standards require or permit assets or liabilities to be measured at fair value, but it does not expand the use of fair value in any new circumstances. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007. The effect of adopting SFAS 157 is not expected to have a significant effect on our reported financial position or earnings, but it will require additional disclosure regarding our derivative instruments when adopted.

In February 2007, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities -Including an Amendment of FASB Statement No. 115* ("SFAS 159"), was issued. SFAS 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The effect of adopting SFAS 159 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, 2007, 2006 or 2005. 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 management and key employees. Granting of awards may increase our general and administrative expenses subject to the size and timing of the grants. See Note 5 to our consolidated financial statements.

Public company expenses

Our general and administrative expenses increased in connection with the completion of our IPO and as a result of us operating as a public company. This increase consisted of legal and accounting fees and additional expenses associated with compliance with the Sarbanes Oxley Act of 2002 and other regulations. We anticipate that our ongoing general and administrative expenses also will increase as a result of being a publicly traded company. This increase will be due primarily to the cost of accounting support services, filing annual and quarterly reports with the SEC, investor relations, directors' fees, directors' and officers' insurance and registrar and transfer agent fees. As a result, we believe that our general and administrative expenses for future periods will increase significantly.

Results of operations

Years ended December 31, 2007 and 2006

	Year Ended December 31,	
	2007	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 expenses	$ 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 are entering into a mix of swaps and collars in 2007, which results in less volatility to the results of operations.

Lease operating expense. Our lease operating expenses 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 lease operating expense 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 (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 4.1% 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 under the contribution agreement on November 14, 2007.

Years ended December 31, 2006 and 2005

	Year Ended December 31,	
	2006	2005
Revenues (in thousands):		
Gas	$41,851	$40,085
Oil	4,821	3,179
Total oil and gas sales	$46,672	$43,264
Realized gain on commodity derivatives	6,222	(2,924)
Total oil and gas sales including derivative impact	52,894	40,340
Production:		
Gas (MMcf)	6,282	4,668
Oil (MBbls)	77	57
Total (MMcfe)	6,744	5,012
Average prices:		
Gas (per Mcf)	$ 6.66	$ 8.59
Oil (per Bbl)	62.65	55.54
Total (per Mcfe)	$ 6.92	$ 8.63
Realized gain on commodity derivatives (per Mcfe)	0.92	(0.58)
Total per Mcfe including derivative impact	$ 7.84	$ 8.05
Costs and expenses (per Mcfe):		
Lease operating expenses	$ 0.58	$ 0.58
Severance and production taxes	0.26	0.39
Exploration	0.24	0.15
Impairment of non-producing properties	0.08	—
General and administrative	0.36	0.53
Depletion, depreciation and amortization	2.16	1.60

Oil and gas sales. Oil and gas sales increased $3.4 million, or 7.9%, for the year ended December 31, 2006 to $46.7 million from $43.3 million for the year ended December 31, 2005. The increase in sales principally resulted from a 34.6% increase in production, as we drilled and completed 81 gross (53.3 net) wells in 2006. The effects of increased production were offset by a decrease in price. The average price before the effect of commodity derivatives decreased $1.71 per Mcfe, or 19.8%, from $8.63 per Mcfe in 2005 to $6.92 per Mcfe in 2006 as the 2005 period included the effects of the spike in gas prices after Hurricane Katrina and Hurricane Rita. Gas sales represented 89.7% of the total oil and gas sales in 2006 compared to 92.7% in 2005.

Commodity derivative activities. Realized gains from our commodity derivative activity increased our earnings $6.2 million for the year ended December 31, 2006. In comparison, realized losses from our commodity derivative activity decreased our earnings $2.9 million for the year ended December 31, 2005. The change in fair value of commodity derivatives was an $8.7 million increase during the year ended

December 31, 2006 and a $4.2 million decrease during the year ended December 31, 2005. During the years ended December 31, 2005 and 2006, we used gas swaps to mitigate commodity price risk. During 2005, commodity prices tended to be higher than the notional prices specified in our swap agreements, which resulted in a loss to us. In contrast, during 2006, commodity prices tended to be lower than the prices specified in our swap agreements, which resulted in a gain to us.

Lease operating expense. Our lease operating expenses increased $1.0 million, or 33.7%, for the year ended December 31, 2006 to $3.9 million from $2.9 million for the year ended December 31, 2005. This increase primarily was the result of a $765,000 increase in ad valorem taxes and from increased pumper costs of $200,000 from the continued development of the Ozona Northeast properties.

Severance and production taxes. Our production taxes decreased $239,000, or 12.1%, for the year ended December 31, 2006 to $1.7 million from $2.0 million for the year ended December 31, 2005. The decrease in production taxes is a function of increased oil and gas revenues that were more than offset by refunds received applicable to prior years. 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. During 2005, we were still awaiting approvals for abatements on several of our Ozona Northeast wells. We received such approvals during 2006, which resulted in the refunds mentioned above.

Exploration and impairment of non-producing properties. Our exploration costs increased $907,000 to $1.6 million for the year ended December 31, 2006 from $734,000 for the year ended December 31, 2005. 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. The 2005 period included dry hole costs of $902,000 from Pecos County and $285,000 from the same well mentioned above in Ozona Northeast. Additionally, the 2005 period included the recoupment of $564,000 of geological evaluation costs from a participant in the Pecos County project. The balance of the 2005 expense is geological and geophysical costs mostly attributable to Ozona Northeast.

Our impairment of non-producing properties of $558,000 in 2006 arose from the abandonment of our leasehold position in Pecos County. As a result of the abandonment, we no longer anticipate incurring any costs related to this area.

General and administrative. Our general and administrative expenses decreased $243,000, or 9.1%, to $2.4 million for the year ended December 31, 2006 from $2.7 million for the year ended December 31, 2005. The decrease in general and administrative expense was principally due to the accrual in 2005 of bonuses totaling approximately $800,000 that did not recur in 2006, offset by increases in 2006 for professional fees, the number of employees and increases in their compensation and benefits. Additionally, operating overhead recoveries in 2006 were $514,000 as compared to $408,000 in 2005.

Depletion, depreciation and amortization (DD&A). Our DD&A expense increased $6.5 million, or 81.6%, to $14.5 million for the year ended December 31, 2006 from $8.0 million for the year ended December 31, 2005. Our DD&A expense per Mcfe produced increased by $0.56, or 35.0%, to $2.16 per Mcfe for the year ended December 31, 2006, as compared to $1.60 per Mcfe for the year ended December 31, 2005. This increase was primarily attributable to increased production and increased oil and gas property costs in 2006.

Interest expense, net. Our interest expense increased $3.0 million, or 375%, to $3.8 million for the year ended December 31, 2006 from $802,000 for the year ended December 31, 2005. This significant increase was a function of increased borrowings under our revolving credit facility and an increase in interest rates during 2006. Interest rates attributable to amounts outstanding under our revolving credit facility amounted to 6.75% at December 31, 2005, compared with 7.75% at December 31, 2006.

Income taxes. Income taxes increased $4.8 million, or 67.3%, to $11.8 million for the year ended December 31, 2006 from $7.0 million for the year ended December 31, 2005. Income taxes increased consistent with our income before tax, offset by a decrease in our effective tax rates, which amounted to 36.8% and 35.7% for the years ended December 31, 2005 and 2006, respectively. Our effective tax rate decreased due primarily to a change in the tax law in the State of Texas which changed the tax from 4.5% of net income to 1% of our "margin," as defined in the new law. Based on this change in the Texas tax law, we reduced our deferred tax liability by approximately $1.1 million for the year ended December 31, 2006.

Liquidity and capital resources

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

For the year ended December 31, 2007, we used the $73.6 million proceeds from the IPO, $84.3 million of net proceeds from bank and convertible debt borrowings and cash flow from operations of $30.7 million to fund:

- $51.8 million of capital expenditures related to our drilling program activities,
- $917,000 investment in a Canadian-based private exploration company,
- repayment of $111.9 million on our credit facility,
- payment of $1.5 million of offering costs related to our IPO, and
- repurchase of $22.5 million of stock held by the selling stockholder.

For the year ended 2006, we used $34.3 million of cash flow from operations and $3.5 million of proceeds from borrowings under a note with one of our stockholders and our revolving credit facility and available cash to fund $59.4 million for our drilling program and $1.3 million to repurchase shares.

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 initial public offering.

For the year ended December 31, 2006, our primary sources of cash were from financing and operating activities. Approximately $18.2 million from borrowings 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 drilling program, the acquisition of another working interest in the Ozona Northeast field and $1.3 million to repurchase shares and cancel stock options.

For the year ended December 31, 2005, cash flow from operations of $40.6 million, borrowings under our revolving credit facility of $29.3 million and $3.0 million from the issuance of common stock provided the funds to drill additional wells in the Ozona Northeast field.

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 2006 and 2007, our cash flows from operations decreased due mostly to lower oil and gas sales and higher general and administrative expenses during the year ended December 31, 2007. In comparing 2005 and 2006, our cash flows from operations declined slightly due to a $6.2 million decrease in working capital components partially offset by the increase in oil and gas sales in 2006.

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

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash flows provided by operating activities	$ 30,746	$ 34,305	$ 40,588
Cash flows used in investing activities	(52,940)	(59,384)	(72,224)
Cash flows provided by financing activities	22,062	26,771	32,199
Effect of Canadian exchange rate	6	—	—
Net (decrease) increase in cash and cash equivalents	$ (126)	$ 1,692	$ 563

Operating activities

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.

Net cash provided by operating activities decreased from $40.6 million in 2005 to $34.3 million in 2006. In comparing 2005 and 2006, our cash flows from operations declined $6.3 million in part due to a decrease in working capital components partially offset by the increase in oil and gas sales and net income in 2006 from our continued development of the Ozona Northeast field in West Texas.

Investing activities

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

	2007	2006
Exploration and development costs:		
Ozona Northeast	$27,986	$52,303
Cinco Terry	10,586	3,176
North Bald Prairie	4,974	—
El Vado East	—	—
Boomerang	2,496	—
Northeast British Columbia	1,235	—
Lease acquisition, geological, geophysical and other(1)	4,920	3,873
Totals	$52,197	$59,352

(1) Includes $3.0 million for undeveloped leaseholds in our British Columbia prospect and $2.5 million for undeveloped leaseholds in our El Vado East prospect during the year ended December 31, 2007. Additionally, we recovered $1.4 million of our initial investment in the Boomerang prospect acreage from the original owner's election to participate in the project during the year ended December 31, 2007. Includes $3.5 million that was invested in the undeveloped leaseholds in our Boomerang prospect for the year ended December 31, 2006.

The majority of our cash flows used in investing activities for the year ended December 31, 2005 were used for the development of the Ozona Northeast field.

We have established an exploratory and development budget of $64.3 million 2008. Our budgets are established based on expected volumes to be produced and commodity prices.

Financing activities

We borrowed $84.3 million under convertible notes and our revolving credit facility in 2007 as compared to $119.5 million net 2006. We repaid a total of $111.9 million and $101.4 million of amounts outstanding under our credit facility for the years ended December 31, 2007 and 2006, respectively. In addition, we spent $1.3 million in the first six months of 2006 to purchase common stock and related options from a former employee. For 2005, we borrowed $103.8 million from our revolving credit facility, repaid $74.5 million under the facility and received $3.0 million from the issuance of common stock.

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

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

During 2006, we sold approximately $6.5 million of common stock. These proceeds were primarily used to fund the acquisition of our Boomerang prospect and drilling costs for our Cinco Terry project.

In February 2007, we entered into an amended and restated $100 million revolving credit facility with The Frost National Bank and JPMorgan Chase, NA. As of December 31, 2007, we had no outstanding balance under the credit facility with a borrowing base of $75 million. We currently have $13.8 million in long-term debt outstanding under our revolving credit facility. In January 2008, we entered into a $200 million revolving credit facility that superseded and terminated the prior $100 million revolving credit facility. The borrowing base under the new credit agreement remained $75 million at February 29, 2008. The borrowing base is subject to adjustment at least twice each year. The assessment by the bank petroleum engineers is based on their evaluation of the future cash flows from proved oil and gas reserves using the bank's pricing parameters.

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 and borrowings under our revolving credit facility will finance substantially all of our anticipated drilling, exploration and capital needs in 2008. We may also use our revolving credit facility for possible acquisitions, temporary working capital needs and any expansion of our drilling program through 2008.

Future capital expenditures for 2008

The following table summarizes information regarding our historical 2007 and estimated 2008 capital expenditures. We will be required to meet our needs from our internally generated cash flow, debt financings and equity financings. The estimated capital expenditures are subject to change depending upon a number of factors, including the results of our development and exploration efforts, the availability of sufficient capital resources to us and other participants for drilling prospects, economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability of drilling rigs and crews, our financial results and the availability of leases on reasonable terms and our ability to obtain permits for the drilling locations.

	Estimated Year Ended December 31, 2008	Historical Year Ended December 31, 2007
	(In thousands)	
Capital expenditures:		
Ozona Northeast		
Acquisition of Neo Canyon	$ —	$ 60,225
Development	29,500	27,986
Cinco Terry	10,900	10,586
North Bald Prairie	14,400	4,974
El Vado East	3,600	—
Boomerang	1,800	2,496
Northeast British Columbia	3,200	1,235
Lease acquisition, geological, geophysical and other	900	4,920
Total capital expenditures	$64,300	$112,422

Credit facility

In February 2007, we entered into an amended and restated $100 million revolving credit facility with The Frost National Bank and JPMorgan Chase, NA. In January 2008, we entered into a new $200 million revolving credit facility with The Frost National Bank and JPMorgan Chase, NA that superseded and terminated the prior revolving credit facility.

The availability of funds under our revolving credit facility is subject to a borrowing base which was initially set at, and currently is, $75 million. The borrowing base will be redetermined every six months or, upon the election by us or the bank, one additional time each calendar year.

Our revolving credit facility provides for interest on outstanding amounts to accrue at a rate calculated, at our option, at either (i) the base rate, which is the bank's prime rate, or (ii) the sum of the LIBOR plus a margin which ranges from 1.25% to 2.0% per annum, as applicable, as amounts outstanding under our revolving credit facility increase as a percentage of the borrowing base. In addition, we pay an annual commitment fee of 0.375% of non-utilized borrowings available under our revolving credit facility.

We are subject to a financial covenant requiring maintenance of a minimum modified ratio of current assets to current liabilities. In addition, we are subject to covenants restricting 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.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets including a guarantee by two of our subsidiaries. All outstanding amounts under our revolving credit facility are due and payable in July 2010.

Contractual commitments

In April 2007, we signed a five-year lease for approximately 13,000 square feet of new office space in Fort Worth, Texas. In January 2008, we began rent payments of approximately $20,000 per month, including common area expenses. We have a lease for our prior space in Fort Worth, Texas that expires in May 2009. Our obligation under this lease is approximately $119,000 per year. At December 31, 2007, we had signed subleases for approximately two-thirds of our prior office space. In February 2008, we subleased the remainder of our prior office space.

The following table summarizes these commitments as of December 31, 2007 (in thousands):

Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Operating lease obligations(1)	1,442	374	841	227	—
Asset retirement obligations	548	—	—	—	548
Employment agreements with executive officers and other key personnel(2)	1,300	1,300	—	—	—
Total	$3,290	$1,674	$841	$227	$548

(1) Operating lease obligations are for office space. We will receive $165,000 for office space that has been subleased from January 2008 through May 2009.

(2) These agreements 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 $1.3 million at December 31, 2007.

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, 2007, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit amounting to $3.0 million, 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

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

To designate a derivative as a cash flow hedge, we document at the commodity derivative's inception our assessment as to whether the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the commodity derivative, if any, is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged.

If, during a commodity derivative's term, we determine the commodity derivative is no longer highly effective, commodity derivative accounting is prospectively discontinued and any remaining unrealized gains or losses on the effective portion of the derivative are reclassified to earnings when the underlying transaction occurs. If it is determined that the designated commodity derivative transaction is not likely to occur, any unrealized gains or losses are recognized immediately in the consolidated statements of income as a derivative fair value gain or loss.

Currently, we have the following commodity derivative positions outstanding:

	Volume (MMBtu)		$/MMBtu		
Period	Monthly	Total	Floor	Ceiling	Fixed
NYMEX — Henry Hub					
Costless collars 2008	186,000	2,230,000	$7.50	$11.45	
Costless collars 2008 (3rd quarter)	100,000	300,000	$7.00	$ 9.10	
Costless collars 2008 (2nd — 4th quarter)	200,000	1,800,000	$9.00	$12.20	
Costless collars 2009	180,000	2,160,000	$7.50	$10.50	
Costless collars 2009	130,000	1,560,000	$8.50	$11.70	
Fixed price swaps					
2nd quarter 2008	100,000	300,000			$ 8.10
4th quarter 2008	100,000	300,000			$ 8.63
WAHA differential					
Fixed price swaps 2008	186,000	2,230,000			(0.69)
Fixed price swaps 2008 (2nd — 4th quarter)	100,000	900,000			(0.67)
Fixed price swaps 2009	200,000	2,400,000			(0.61)

At December 31, 2007 and December 31, 2006, the fair value of our open derivative contracts was an asset of approximately $868,000 and $4.5 million, respectively.

We have reviewed the financial strength of our commodity derivative counterparty and believe our credit risk to be minimal. Our commodity derivative counterparty is a participant in our credit facility and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

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(T). *Controls and Procedures.*

Disclosure controls and procedures

Our management, with the participation of our 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, 2007. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2007, 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 Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal control over financial reporting

No changes to our internal control over financial reporting occurred during the year ended December 31, 2007 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). The SEC's rules under Section 404 of the Sarbanes-Oxley Act of 2002 become applicable to us beginning with our Annual Report on Form 10-K for the year ending December 31, 2008 to be filed in the first quarter of 2009. We cannot give any assurance, however, that our internal controls will be effective when Section 404 becomes applicable to us. Ineffective internal controls could cause investors to lose confidence in our reported financial information and could result in a lower trading price for our securities.

This report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

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

None.

PART III

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

Our executive officers and directors and their ages and positions as of March 14, 2008, are as follows:

Name	Age	Position
J. Ross Craft	51	President, Chief Executive Officer and Class III Director
Steven P. Smart	53	Executive Vice President, Chief Financial Officer and Treasurer
J. Curtis Henderson	45	Executive Vice President and General Counsel
Glenn W. Reed	56	Senior Vice President — Operations
Ralph P. Manoushagian	56	Senior Vice President — Land
Bryan H. Lawrence	65	Chairman, Class III Director
James H. Brandi	59	Class II Director
James C. Crain	59	Class II Director
Sheldon B. Lubar	78	Class I Director
Christopher J. Whyte	51	Class I Director

J. Ross Craft has been our President and Chief Executive Officer and a member of our board of directors since our inception in September 2002. Before Approach, Mr. Craft co-founded Athanor Resources Inc., an international exploration and production company with operations in the United States and Tunisia, in 1998 and was its Executive Vice President from 1998 until its merger with Nuevo Energy Company in September 2002. From 1988 to 1997, Mr. Craft served in various positions with American Cometra Inc., an independent exploration and production company with operations in the United States, including Vice President — Operations from 1995 to 1997. American Cometra was sold in two parts, to Range Resources in 1995 and Pioneer Natural Resources in 1997. Mr. Craft has 27 years of experience in the oil and gas industry. Mr. Craft, who holds a B.S. in Petroleum Engineering from Texas A&M University, is a registered Professional Engineer licensed in the State of Texas. In addition to membership in the Society of Petroleum Engineers, Mr. Craft is a member of the Texas Oil and Gas Association and Independent Petroleum Association of America. Mr. Craft has served on the board of the Fort Worth chapter of the Society of Petroleum Engineers as well as on the board of the Fort Worth Petroleum Engineers Club where his last position was President. In addition to the above, Mr. Craft is an Eagle Scout. Mr. Craft is the brother-in-law of J. Curtis Henderson, our Executive Vice President and General Counsel.

Steven P. Smart has been our Treasurer since our inception in September 2002. Mr. Smart was named Vice President — Finance in August 2005, and promoted to Executive Vice President and Chief Financial Officer in June 2007. From 2000 to 2002, Mr. Smart was Controller and Treasurer of Prize Energy Corp., a public exploration and production company. From 1998 to 2000, Mr. Smart was a Senior Manager in the Energy Industry group at Arthur Andersen LLP. Prior to 2000, Mr. Smart served in senior executive financial positions with several public and private oil and gas companies, including Magnum Hunter Resources Inc. and Saxon Oil Co. Mr. Smart began his career in public accounting with Deloitte & Touche (formerly Touche Ross). Mr. Smart has more than 30 years of experience in both public and private companies in the oil and gas industry. Mr. Smart, who holds a B.B.A. in Accounting from Angelo State University, is a Certified Public Accountant with an active license.

J. Curtis Henderson joined us in February 2007 as Executive Vice President and General Counsel. From 2005 to 2007, Mr. Henderson served as President and Chief Executive Officer of Coterie Capital Partners, Ltd., a private equity partnership in Dallas, Texas. From 1998 to 2005, Mr. Henderson served as General Counsel of Nucentrix Broadband Networks, Inc., a public broadband wireless telecommunications company based in Dallas. While he was at Nucentrix, Mr. Henderson oversaw the sale of that company to an affiliate of Nextel Communications Inc. under Section 363 of the United States Bankruptcy Code in 2004. Mr. Henderson began his career as a lawyer in the corporate and securities section of Locke Lord Bissell & Liddell (formerly

Locke Purnell Rain Harrell). Mr. Henderson has over 20 years experience in public and private securities, mergers and acquisitions, corporate finance and regulatory affairs. Mr. Henderson holds a B.A. in Political Science from Austin College and a J.D. from Washington and Lee University School of Law. Mr. Henderson is the brother-in-law of J. Ross Craft, our Chief Executive Officer and President.

Glenn W. Reed has been our Senior Vice President — Operations since June 2007. Mr. Reed served as our Vice President — Operations from our inception in September 2002 to June 2007. Mr. Reed was Manager of Operations for Athanor Resources Inc. from 1999 to 2002, where he was responsible for petroleum engineering and operations before Athanor was sold to Nuevo Energy Company in September 2002. From 1988 to 1999, Mr. Reed supervised operations for American Cometra. Mr. Reed, who holds a B.S. in Petroleum Engineering from Texas Tech University, is a registered Professional Engineer licensed in Texas and has 28 years of experience in the oil and gas industry.

Ralph P. Manoushagian has been our Senior Vice President — Land since June 2007. Mr. Manoushagian joined us in 2004 as Land Manager. In 2003, Mr. Manoushagian worked as an independent landman. From 2001 to 2003, Mr. Manoushagian was the President of Hudco Fuels, a privately owned fuel distributorship. Mr. Manoushagian has been an active landman and oil and gas operator for 30 years. Mr. Manoushagian, who holds a B.B.A. in Finance from the University of North Texas, has been a Certified Professional Landman since 1988. Mr. Manoushagian is a director of the First Financial Bank of Southlake, Texas. He previously served as a director and Vice President of the Texas Independent Producers and Royalty Owners and as a director of the Texas Alliance of Energy Producers.

Bryan H. Lawrence has been a member of our board of directors since 2002. Mr. Lawrence is a founder and Senior Manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies in the energy industry. The Yorktown group of investment partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of Crosstex Energy, Inc. and Crosstex Energy GP, LLC, midstream natural gas companies; Hallador Petroleum Company, an independent company engaged in the production of coal and the exploration and production of oil and natural gas; the general partner of Star Gas Partners, L.P., a home heating oil distributor and services provider; Winstar Resources, a public Canadian oil and gas company; Ellora Energy Inc., an independent oil and gas company; and certain non-public companies in the energy industry in which the Yorktown group of investment partnerships hold equity interests. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University.

James H. Brandi joined us as a director in June 2007. Since November 2005, Mr. Brandi has been a partner at Hill Street Capital, a private investment and financial advisory firm. From 2000 until November 2005, Mr. Brandi was a Managing Director at UBS Securities, LLC, where he was the Deputy Global Head of the Energy and Power Group. Prior to 2000, Mr. Brandi was a Managing Director at Dillon, Read & Co. Inc. and later its successor firm, UBS Warburg, concentrating on transactions in the energy and consumer goods areas. Mr. Brandi serves on the boards of Energy East Corporation, a utility holding company, and Armstrong Land Company, LLC, a coal reserves owning company. Mr. Brandi is a trustee of The Kenyon Review and a former trustee of Kenyon College. Mr. Brandi holds a B.A. in History from Yale University and an M.B.A. from Harvard Business School and attended Columbia Law School as a Harlan Fiske Stone Scholar.

James C. Crain joined us as a director in June 2007. Mr. Crain has been involved in the energy industry for over 30 years, both as an attorney and as an executive officer. Since 1984, Mr. Crain has been an officer of Marsh Operating Company, an investment management company focusing on energy investing, including his current position of President which he has held since 1989. Mr. Crain has served as general partner of Valmora Partners, L.P., a private investment partnership that invests in the oil and gas sector, among others, since 1997. Prior to joining Marsh in 1984, Mr. Crain was a partner in the law firm of Jenkens & Gilchrist, where he headed the firm's energy section. Mr. Crain currently is a director of Crosstex Energy, Inc. and Crosstex Energy GP, LLC, midstream natural gas companies, and GeoMet, Inc., a coalbed methane natural gas exploration and production company. Mr. Crain holds a B.B.A., an M.P.A. and a J.D. from the University of Texas at Austin.

Sheldon B. Lubar joined us as a director in June 2007. Mr. Lubar has been Chairman of the Board of Lubar & Co. Incorporated, a private investment and venture capital firm he founded, since 1977. He was Chairman of the Board of Christiana Companies, Inc., a logistics and manufacturing company, from 1987 until its merger with Weatherford International in 1995. Mr. Lubar is currently a director of Crosstex Energy, Inc. and Crosstex Energy GP, LLC, midstream natural gas companies; Weatherford International, Inc., an energy services company; Ellora Energy Inc., an independent oil and gas company; and the general partner of Star Gas Partners, L.P., a home heating oil distributor and services provider. Mr. Lubar previously held governmental appointments under three United States Presidents, including Commissioner of the White House Conference on Small Business from 1979 to 1980 under President Carter, Assistant Secretary, Housing Production and Mortgage Credit, Department of Housing and Urban Development, Commissioner of the Federal Housing Administration and Director of the Federal National Mortgage Association from 1973 to 1974 under Presidents Nixon and Ford. Mr. Lubar is a past president of the Board of Regents of the University of Wisconsin System. Mr. Lubar holds a B.S. in Business Administration and a J.D. from the University of Wisconsin — Madison. Mr. Lubar was awarded an honorary Doctor of Commercial Science degree from the University of Wisconsin — Milwaukee.

Christopher J. Whyte has been a member of our board of directors since June 2007. Mr. Whyte has been President, Chief Executive Officer and a director of PetroSantander Inc., which owns and operates oil and gas production in Colombia, Kansas and Brazil, since 1995. Mr. Whyte holds a B.A. from the University of Pittsburgh.

Additional information required under Item 10, "Directors, Executive Officers and Corporate Governance" will be provided in our proxy statement for our 2008 annual meeting of stockholders. 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 definitive proxy statement for our 2008 annual meeting of stockholders to be filed with the SEC on or before April 29, 2008, 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 definitive proxy statement for our 2008 annual meeting of stockholders to be filed with the SEC on or before April 29, 2008, which is incorporated herein by reference.

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, 2007.

	(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))
Plan category:			
Equity compensation plans approved by stockholders	479,991	$7.07	1,513,559
Equity compensation plans not approved by stockholders	—	—	—

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 2008 annual meeting of stockholders to be filed with the SEC on or before April 29, 2008, which is 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 2008 annual meeting of stockholders to be filed with the SEC on or before April 29, 2008, 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 56 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.

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.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

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 or "PUDs." 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 estimated future net revenues from proved oil and gas reserves at a date indicated 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 Securities and Exchange Commission'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 future net revenues 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 reserves by estimated 2008 production of 8.3 Bcfe (based on the mid-range of company guidance as of March 15, 2008) 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. Tcfe. Trillion cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.

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 27, 2008

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 on March 27, 2008.

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.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Approach Resources Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2007. These consolidated 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ *HEIN & ASSOCIATES LLP*
Dallas, Texas
March 26, 2008

Approach Resources Inc. and Subsidiaries

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

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash	$ 4,785	$ 4,911
Accounts receivable:		
Joint interest owners	5,272	4,813
Oil and gas sales	5,524	3,458
Unrealized gain on commodity derivatives	793	4,505
Prepaid expenses and other current assets	773	424
Total current assets	17,147	18,111
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	266,905	155,628
Furniture, fixtures and equipment	433	255
	267,338	155,883
Less accumulated depletion, depreciation and amortization	(36,860)	(23,771)
Net properties and equipment	230,478	132,112
INVESTMENT	917	—
UNREALIZED GAIN ON COMMODITY DERIVATIVES	75	—
OTHER ASSETS	109	86
Total assets	$248,726	$150,309
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 5,459	$ 6,246
Oil and gas sales payable	1,794	4,940
Accrued liabilities	14,764	4,235
Total current liabilities	22,017	15,421
NON-CURRENT LIABILITIES:		
Long-term debt	—	47,619
Deferred income taxes	26,342	17,549
Asset retirement obligations	548	148
Total liabilities	48,907	80,737
COMMITMENTS AND CONTINGENCIES (Note 10)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value, 10,000,000 shares authorized none outstanding	—	—
Common stock, $0.01 par value, 90,000,000 shares authorized, 20,622,746 and 9,735,312 shares issued and outstanding, respectively	206	97
Additional paid-in capital	166,141	43,001
Retained earnings	33,367	30,658
Loans to stockholders	—	(4,184)
Accumulated other comprehensive income	105	—
Total stockholders' equity	199,819	69,572
Total liabilities and stockholders' equity	$248,726	$150,309

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, 2007	2006	2005
REVENUES:			
Oil and gas sales	$ 39,114	$ 46,672	$ 43,264
EXPENSES:			
Lease operating	3,815	3,889	2,910
Severance and production taxes	1,659	1,736	1,975
Exploration	883	1,640	733
Impairment of non-producing properties	267	558	—
General and administrative	12,667	2,416	2,659
Depletion, depreciation and amortization	13,098	14,551	8,011
Total expenses	32,389	24,790	16,288
OPERATING INCOME	6,725	21,882	26,976
OTHER:			
Interest expense, net	(5,219)	(3,814)	(802)
Realized gain (loss) on commodity derivatives	4,732	6,222	(2,925)
Change in fair value of commodity derivatives	(3,637)	8,668	(4,163)
INCOME BEFORE INCOME TAX (BENEFIT) PROVISION	2,601	32,958	19,086
INCOME TAX (BENEFIT) PROVISION	(108)	11,756	7,028
NET INCOME	$ 2,709	$ 21,202	$ 12,058
EARNINGS PER SHARE:			
Basic	$ 0.25	$ 2.26	$ 1.32
Diluted	$ 0.24	$ 2.20	$ 1.32
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	10,976,251	9,368,614	9,107,092
Diluted	11,183,707	9,634,912	9,107,092

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, 2005, 2006 and 2007 (In thousands, except 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, 2005	8,981,889	$ 90	31,451	$ (2,602)	$(4,063)	$ —	$ 24,876
Issuance of common stock	197,832	2	2,989	—	—	—	2,991
Accrual of interest on loans to stockholders	—	—		—	(235)	—	(235)
Net income	—	—	—	12,058	—	—	12,058
BALANCES, December 31, 2005	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

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Cash Flows
(In thousands)

	For the Years Ended December 31,		
	2007	2006	2005
OPERATING ACTIVITIES:			
Net income	$ 2,709	$ 21,202	$ 12,058
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	13,098	14,551	8,011
Amortization of loan origination fees	117	72	47
Non cash interest expense on convertible notes	2,095	—	—
Change in fair value of commodity derivatives	3,637	(8,668)	4,163
Impairment of non-producing leasehold costs	267	558	—
Dry hole costs	883	1,614	1,187
Share-based compensation expense	4,646	34	—
Deferred income taxes	(296)	11,102	6,448
Interest earned on loans to stockholders	—	—	(235)
Changes in operating assets and liabilities:			
Accounts receivable	(2,657)	7,389	(9,779)
Prepaid expenses and other current assets	(349)	221	(68)
Accounts payable	(787)	(14,284)	12,129
Oil and gas payables	(3,146)	(1,704)	5,269
Accrued liabilities	10,529	2,218	1,358
Cash provided by operating activities	30,746	34,305	40,588
INVESTING ACTIVITIES:			
Advances under note receivable	—	—	(4,152)
Payments received under note receivable	—	—	5,698
Additions to oil and gas properties	(51,845)	(59,352)	(73,730)
Additions to other property and equipment, net	(178)	(32)	(40)
Investments	(917)	—	—
Cash used in investing activities	(52,940)	(59,384)	(72,224)
FINANCING ACTIVITIES:			
Loan origination fees	(140)	(69)	(117)
Borrowings under credit facility	64,285	119,547	103,775
Repayment of amounts outstanding under credit facility	(111,904)	(101,353)	(74,450)
Proceeds from convertible notes	20,000	—	—
Borrowing from stockholder	—	3,500	—
Proceeds from issuance of common stock	72,377	6,498	2,991
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	22,062	26,771	32,199
CHANGE IN CASH AND CASH EQUIVALENTS	(132)	1,692	563
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	6	—	—
CASH AND CASH EQUIVALENTS, beginning of year	4,911	3,219	2,656
CASH AND CASH EQUIVALENTS, end of year	$ 4,785	$ 4,911	$ 3,219
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 4,117	$ 3,269	$ 600
Cash paid for income taxes	$ 1,287	$ 2	$ —
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Conversion of stockholder note into common stock	$ —	$ 3,500	$ —
Acquisition of oil and gas properties	$ 60,225	—	—
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

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

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

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, 2007 and 2006.

Oil and Gas Properties and Operations

Capitalized Costs

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

	2007	2006
Mineral interests in properties		
Unproved properties	$ 10,845	$ 4,207
Proved properties	10,937	12,166
Wells and related equipment and facilities	234,067	137,753
Uncompleted wells, equipment and facilities	11,056	1,502
Total costs	266,905	155,628
Less accumulated depreciation, depletion and amortization	(36,622)	(23,622)
	$230,283	$132,006

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, 2007 or 2006. 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, 2007, 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 $13.0 million, $14.5 million and $8.0 million for the years ended December 31, 2007, 2006 and 2005, 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 $267,000 and $558,000 during the years ended December 31, 2007 and 2006, respectively related to our assessment of unproved properties. 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 will expire in April 2008. The impairment recorded during the year ended December 31, 2006, 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. We noted no impairments of our unproved properties for the year ended 2005.

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 No. 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, 2007, 2006 or 2005.

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, 2007 or 2006.

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 pumpers' salaries, saltwater disposal, ad valorem taxes, 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, 2007 and 2006, we sold substantially all of our oil and gas produced to five purchasers. Additionally, substantially all of our accounts receivable related to oil and gas sales were due from those five purchasers at December 31, 2007 and 2006. 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. As a result of historically strong prices of oil and gas, the demand for oilfield and drilling services has risen, and the costs of these services may increase. We are particularly sensitive to higher rig costs and drilling rig availability, as we presently have several rigs under contract, one of which is on a well-to-well basis. 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 $88,000, $64,000 and $55,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

Note Receivable

In conjunction with a farmout agreement, we entered into a full recourse revolving promissory note for the benefit of a working interest owner to fund its costs incurred drilling wells under the farmout agreement. Effective December 31, 2005, we purchased the working interest for $10.5 million by the retirement of the note receivable and accrued interest of approximately $3.5 million and the payment of approximately $7.0 million in January 2006. The note provided for interest at six percent per annum and was collateralized by the working interest in the wells drilled under the farmout agreement.

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 combined 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 "change in fair value of 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, 2007 and 2006:

	2007	2006
Capital expenditures accrued	$13,168	$2,362
Operating expenses and other	1,380	559
Federal income taxes	216	1,314
	$14,764	$4,235

Asset Retirement Obligations

Our asset retirement obligations relate to future plugging and abandonment expenses on oil and gas properties. The asset retirement obligations were approximately $550,000 and $150,000 at December 31, 2007 and 2006, respectively. Based on the expected timing of payments, the full asset retirement obligation is classified as non-current.

Comprehensive Income

For the years ended December 31, 2006 and 2005, there were no elements of comprehensive income other than net income. Following is a summary of our comprehensive income for the year ended December 31, 2007:

Net income	$2,709
Other comprehensive income:	
Foreign currency translation adjustments	105
Comprehensive income	$2,814

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 year ended December 31, 2007, we recognized a $105,000 translation gain. Transaction gains and losses for the years ended December 31, 2006 and 2005 were insignificant.

Share-based Compensation

Prior to January 1, 2006, we accounted for stock option awards granted under our 2003 Stock Option Plan in accordance with the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB 25") and related Interpretations, as permitted by Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation ("SFAS No. 123").

Share-based employee compensation expense was not recognized in the Company's consolidated statements of operations prior to January 1, 2006, as all stock option awards granted had an exercise price equal to or greater than the estimated fair market value of the common stock on the date of the grant. As permitted by SFAS No. 123, we reported pro forma disclosures presenting results and earnings (loss) per share as if we had used the fair value recognition provisions of SFAS No. 123 in the Notes to Consolidated Financial Statements. Share-based compensation related to non-employees and modifications of options granted were accounted for based on the fair value of the related stock or options in accordance with SFAS No. 123 and its interpretations.

Effective January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment ("SFAS No. 123(R)"), which requires the measurement and recognition of compensation expense for all share-based payment awards to employees and directors based on estimated fair values. We adopted SFAS No. 123(R) using the modified prospective transition method. In accordance with the modified prospective application provisions of SFAS No. 123(R), compensation cost for the portion of awards that were outstanding as of January 1, 2006, for which the requisite service was not rendered, are recognized as the requisite service is rendered, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R). Additionally, compensation costs for awards granted after January 1, 2006 are recognized over the requisite service period based on the grant-date fair value. In accordance with the modified prospective transition method, our consolidated financial statements for prior periods have not been restated to reflect the impact of SFAS No. 123(R).

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, 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(1)		60,548	
Convertible notes(2)	—	—	
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

	Year Ended December 31, 2005		
	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic earnings per share:			
Net income	$12,058	9,107,092	$1.32
Effect of dilutive securities:			
Stock options, treasury method(3)		—	
Net income plus assumed conversions	$12,058	9,107,092	$1.32

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

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

(3) Options to acquire 375,000 shares of our common stock were anti-dilutive for the year ended December 31, 2005.

The share amounts for the years ending 2006 and 2005 have been restated to reflect the contribution agreement and the stock split discussed in Note 2.

Recently Issued Accounting Pronouncements

In March 2008, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 ("SFAS 161"). SFAS 161 amends and expands the disclosure requirements of FASB Statement No. 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 No. 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, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141 (revised 2007), Business Combinations ("SFAS No. 141(R)"). SFAS No. 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 No. 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 No. 160, Non-controlling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51 ("SFAS No. 160"). SFAS No. 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 Company is currently evaluating the requirements of SFAS No. 160 and has not yet determined the impact of adoption, if any, on its financial position, results of operations or cash flows.

In September 2006, Statement of Financial Accounting Standards No. 157, Fair Value Measurements ("SFAS 157"), was issued. SFAS 157 provides guidance for using fair value to measure assets and liabilities. It applies whenever other standards require or permit assets or liabilities to be measured at fair value, but it does not expand the use of fair value in any new circumstances. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007. The effect of adopting SFAS 157 has not been determined, it is not expected to have a significant effect on our reported financial position or earnings, but it will require additional disclosure on our derivative instruments when adopted.

In February 2007, SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities-Including an Amendment of FASB Statement No. 115 ("SFAS 159"), was issued. SFAS 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The effect of adopting SFAS 159 has not been determined, but it is not expected to have a significant effect on reported financial position or earnings.

2. Contribution Agreement and Initial Public Offering

Contribution Agreement

On November 14, 2007, the Company acquired all of the outstanding capital stock of AOG and acquired the 30% working interest in the Ozona Northeast field (the "Neo Canyon interest") that the Company did not already own from Neo Canyon Exploration, L.P. ("Neo Canyon" or "Selling Stockholder"). Upon the closing of the transactions contemplated by 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 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 $60.2 million, representing 4,239,243 shares of Approach Resources Inc. 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 is pending the filing of Neo Canyon's tax return. As a result, the preliminary purchase price is expected to be finalized during the three months ended June 30, 2008. The following is a summary of the preliminary purchase price and its allocation (in thousands) based on our estimates described above assuming the acquisition occurred on December 31, 2007:

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	9,089
Asset retirement obligations assumed	133
Post-closing purchase price adjustments	132
Total	$60,225
Allocation:	
Wells and equipment and related facilities	$59,434
Mineral interests in oil and gas properties	791
Total	$60,225

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 8, 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.

3. Loans to Stockholders and Stockholder Notes Payable

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

During February 2006, one of our employees voluntarily resigned. At the time of his resignation, the employee held 103,845 shares of ARI common stock and options to acquire 28,845 shares of ARI common stock at $3.33 per share. Additionally, the employee owed us $334,000 of principal and interest under a full-recourse note receivable for the initial purchase of his shares. On February 17, 2006, we entered into an agreement to repurchase the shares and options, net of the principal and interest due under the note receivable. We paid $12.82 per share, the fair value of our common stock on February 17, 2006, for the 103,845 shares, or $1.3 million less the outstanding principal and interest of $334,000 for total cash of $1.0 million. As discussed in Note 5, 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.

Line of Credit

We have a revolving loan agreement with The Frost National Bank and JPMorgan Chase Bank, NA (the "Agreement"), which provides a borrowing base determined by the bank based on oil and gas reserve values. The bank determines our borrowing base semi-annually on or before each March 1 and September 1 based on our oil and gas reserves. We or the bank can each request one additional borrowing base redetermination each calendar year. In February 2007, the line of credit was raised to $100.0 million and the borrowing base was increased to $75.0 million. In June 2007, the maturity date of the Agreement was extended to July 2010. We had no borrowings outstanding under the Agreement at December 31, 2007 while borrowings outstanding at December 31, 2006 were $47.6 million. As of March 26, 2008, we had $13.8 million in long-term debt outstanding under the Agreement. The borrowings bear interest based on the 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. The interest rate at December 31, 2007 was 6.6%. Principal payments are not required until the final maturity date of the agreement, at which time any outstanding loan balances shall be due and payable in full. In addition, the Agreement requires payment of a quarterly fee equal to three eighths of one percent (0.375%) of the unused portion of the borrowing base. The borrowings are collateralized by substantially all of our oil and gas properties. The Agreement contains various covenants, the most restrictive of which requires us to maintain a modified current ratio of at least one. The modified current ratio represents the quotient of our current assets, less any unrealized gains on commodity derivatives plus amounts available under the Agreement divided by our current liabilities less unrealized losses on commodity derivatives. We were in compliance with the covenants at December 31, 2007.

We also have outstanding unused letters of credit under the Agreement totaling $3.0 million at December 31, 2007, which reduce amounts available for borrowing under the Agreement.

In January 2008 we entered into a new, $200.0 million revolving loan agreement ("New Loan Agreement") with ARI as borrower, AOG, Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP as guarantors, and The Frost National Bank and JPMorgan Chase Bank, NA, as lenders. The borrowing base under the New Loan Agreement was initially set at $75.0 million and will be redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves.

5. Share-Based Compensation

In June 2007, the board of directors and stockholders approved the 2007 Stock Incentive Plan ("the 2007 Plan"). Under the 2007 Plan, we may grant 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.

As discussed in Note 1, Significant Accounting Policies — Shared-Based Compensation, effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), using the modified prospective transition method. Share-based compensation expense resulting from the adoption of SFAS No. 123(R) amounted to $4.6 million and $34,000 for the years ended December 31, 2007 and 2006, respectively. Such amounts represent the estimated fair value of options for which the requisite service period elapsed during 2007 and 2006. There was no tax benefit recognized in relation to this change.

Had we followed the fair value recognition provisions of SFAS 123 for the year ended December 31, 2005, our operating results and earnings per share would have been affected as follows, (in thousands, except per share amounts):

	2005
Net income as reported	$12,058
Basic and diluted earnings per share as reported	$ 1.32
Share-based employee compensation costs, net of related tax effects, included in net income as reported	—
Share-based employee compensation costs, net of related tax effects, that would have been included in net income if the fair-value-based method had been applied to all awards	(34)
Pro forma net income as if the fair-value-based method had been applied to all awards	$12,024
Pro forma basic and diluted earnings per share as if the fair-value-based method had been applied to all awards	$ 1.32

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the year ended December 31, 2007. There were no grants during the years ended December 31, 2006 and 2005.

Expected dividends	—
Expected volatility	68%
Risk-free interest rate	3.9%
Expected life	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. 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 No. 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, 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
Exercisable (fully vested) at December 31, 2007	274,041	$ 3.33	6.63	$2,612

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 2.

The fair market value of the stock options granted during the year ended December 31, 2007 was $7.69 per share. Total unrecognized share-based compensation expense from unvested stock options as of December 31, 2007 was $1.5 million, and will be recognized over a remaining service period of 2.86 years. The intrinsic value of the options exercised during the year ended December 31, 2007 was $634,000.

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 411,041 shares with an approximate aggregate market value of $5.2 million at the time of grant were granted during the year ended December 31, 2007. A summary of the status of non-vested shares for the year ended December 31, 2007, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at the beginning of the year	—	$ —
Granted	411,041	12.70
Vested	(368,541)	12.26
Nonvested at the end of the year	42,500	$16.50

The unrecognized compensation of $657,000 related to the nonvested shares will be recognized over a remaining service period of 1.86 years.

6. Income Taxes

Our (benefit) provision for income taxes comprised the following during the years ended December 31, 2007, 2006 and 2005 (in thousands):

	2007	2006	2005
Current:			
Federal	$ 188	$ 550	$ 509
State	—	105	71
Total current	188	655	580
Deferred:			
Federal	(296)	11,243	5,663
State	—	(141)	785
Total deferred	(296)	11,102	6,448
(Benefit) provision for income taxes	$(108)	$11,757	$7,028

Total income (benefit) tax expense differed from the amounts computed by applying the U.S. Federal statutory tax rates to pre-tax income for the years ended December 31, 2007, 2006 and 2005 as follows (in thousands):

	2007	2006	2005
Statutory tax (benefit) at 34%	$ 884	$11,205	$6,490
State taxes (benefit), net of federal impact	29	990	569
Changes in enacted rates	—	(1,077)	—
Permanent differences(1)	609	—	—
Other differences	(35)	(173)	(250)
Change in valuation allowance	(1,595)	812	219
	$ (108)	$11,757	$7,028

(1) Amount primarily relates to the beneficial conversion feature on the convertible notes, see Note 2.

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 No. 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 $26.3 million and $17.5 million at December 31, 2007 and 2006, respectively. Significant components of net deferred tax assets and liabilities are (in thousands):

	December 31, 2007	December 31, 2006
Deferred tax assets:		
Difference in depreciation and capitalization methods — furniture, fixtures and equipment	$ —	$ 28
Net operating loss carryforwards	2,846	1,805
Total deferred tax assets	2,846	1,833
Less: valuation allowance	—	(1,595)
Net deferred tax assets	2,846	238
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods — oil and gas properties	(28,877)	(16,226)
Unrealized gain on commodity derivatives	(301)	(1,561)
Other	(10)	—
Total deferred tax liabilities	(29,188)	(17,787)
Net deferred tax (liability)	$(26,342)	$(17,549)

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	3,011
Total	$8,210

7. Derivatives

We periodically enter into put options, call options, combinations of put and call options (referred to as a costless collar), and swaps to mitigate the risk of fluctuations in commodity prices related to our natural gas production. As discussed in Note 1, Summary of Significant Accounting Policies, we do not designate our derivative instruments as cash flow hedges. At December 31, 2007, we had the following commodity derivative positions outstanding:

	Volume (MMBtu)		$/MMBtu		
Period	**Monthly**	**Total**	**Floor**	**Ceiling**	**Fixed**
NYMEX — Henry Hub					
Costless collar 2008	186,000	2,230,000	$7.50	$11.45	
Costless collar 2009	180,000	2,160,000	$7.50	$10.50	
WAHA differential					
Fixed price swaps 2008	186,000	2,230,000			(0.69)
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 contracts and then obtained mark-to-market valuations for our collar positions from our counterparty and reviewed such valuations for reasonableness based on forward prices in relation to our contractual ceiling and floor prices. Realized gains as losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit loss in the event of nonperformance by the counterparty on our oil and gas swaps. However, we do not anticipate nonperformance by the counterparty over the term of the swaps.

Subsequent to December 31, 2007, we entered into the following commodity derivative positions:

	Volume (MMBtu)		$/MMBtu		
Period	**Monthly**	**Total**	**Floor**	**Ceiling**	**Fixed**
NYMEX — Henry Hub					
Costless collars 2008 (3rd quarter)	100,000	300,000	$7.00	$ 9.10	
Costless collars 2008 (2nd — 4th quarter)	200,000	1,800,000	$9.00	$12.20	
Costless collars 2009	130,000	1,560,000	$8.50	$11.70	
WAHA differential					
Fixed price swaps 2008 (2nd — 4th quarter)	100,000	900,000			$(0.67)
Fixed price swaps					
2nd quarter 2008	100,000	300,000			$ 8.10
4th quarter 2008	100,000	300,000			$ 8.63

8. Convertible Debt

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.

9. Canadian Unconventional Gas Investment

In May 2007, we acquired shares of common stock of a Canadian-based private exploration company focused on tight gas and shale gas opportunities in Canada. Our investment amounted to approximately $917,000 and is a non-controlling interest accounted for using the cost method.

10. 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 $1.3 million at December 31, 2007.

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 in 2009 and 2011. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements, net of sublease collections expected to be received as of December 31, 2007 (in thousands):

2008	$ 374
2009	310
2010	262
2011	269
2012	227
Collections	(165)
Total	$1,277

Rent expense under our lease arrangements amounted to $198,000, $137,000 and $130,000 for the years ended December 31, 2007, 2006 and 2005, 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.

11. Oil and Gas Producing Activities

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

	For the Year Ended December 31,		
	2007	2006	2005
Property acquisition costs:			
Unproved properties	$ 5,480	$ 4,071	$ 369
Proved properties	59,594	356	11,592
Exploration costs	9,897	3,769	1,347
Development costs	37,451	51,820	59,972
Total costs incurred	$112,422	$60,016	$73,280

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

	For the Year Ended December 31,		
	2007	2006	2005
Revenues	$ 39,114	$ 46,672	$ 43,264
Production costs	(5,474)	(5,625)	(4,885)
Exploration expenses	(883)	(1,640)	(733)
Impairment	(267)	(558)	—
Depletion	(13,010)	(14,487)	(7,956)
Income tax expenses	(6,623)	(9,114)	(11,101)
Results of operations	$ 12,857	$ 15,248	$ 18,589

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

The estimates of proved reserves and related valuations for the years ended December 31, 2007, 2006 and 2005 were based upon the reports prepared by DeGolyer and MacNaughton, independent petroleum engineers (for 2007 and 2006) and by Cawley, Gillespie & Associates, Inc., independent petroleum engineers (for 2005). Each year's estimate of proved reserves and related valuations was prepared in accordance with the provisions of Statement of Financial Accounting Standards No. 69 ("SFAS No. 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, 2005, 2006 and 2007, are as follows:

	Natural Gas (MMcf)	Oil & NGLs (MBbl)
Balance — January 1, 2005	57,697	353
Extensions and discoveries	2,755	26
Purchases of minerals in place	6,400	68
Production	(4,666)	(58)
Revisions to previous estimates	40,219	697
Balance — December 31, 2005	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
Proved developed reserves:		
December 31, 2005	47,078	454
December 31, 2006	51,004	496
December 31, 2007	70,251	1,268

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2007, 2006 and 2005:

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.

Year Ended December 31, 2005

Our drilling program in Ozona Northeast resulted in classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. Additionally we purchased the working interests of one of the non-operating participants in Ozona Northeast during 2005, which accounts for the additional quantities listed under purchases of minerals in place. The approval of the 20-acre down spacing in December 2005 and the increase in average gas price attributable to our proved reserves from $6.93 per Mcf at December 31, 2004 to $9.20 per Mcf at December 31, 2005, were the primary reason for the additional 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 No. 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):

	2007	2006	2005
Future cash flows	$1,567,251	$ 709,184	$1,003,363
Future production costs	(401,579)	(198,023)	(193,171)
Future development costs	(191,738)	(108,451)	(101,152)
Future income tax expense	(285,384)	(109,784)	(238,013)
Future net cash flows	688,550	292,926	471,027
10% annual discount for estimated timing of cash flows	(472,590)	(215,049)	(324,588)
Standardized measure of discounted future net cash flows	$ 215,960	$ 77,877	$ 146,439

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, 2007, 2006, and 2005 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):

	2007	2006	2005
Balance, beginning of period	$ 77,877	$ 146,439	$ 60,278
Net change in sales and transfer prices and in production (lifting) costs related to future production	57,231	(106,246)	53,167
Changes in estimated future development costs	(39,506)	(43,229)	(87,109)
Sales and transfers of oil and gas produced during the period	(33,640)	(41,047)	(38,379)
Net change due to extensions, discoveries and improved recovery	107,864	28,418	7,613
Net change due to purchase of minerals in place	97,328	—	17,804
Net change due to revisions in quantity estimates	(21,001)	(22,112)	116,125
Previously estimated development costs incurred during the period	28,026	52,108	53,116
Accretion of discount	12,843	15,546	16,686
Other	8,077	(4,303)	9,616
Net change in income taxes	(79,139)	52,303	(62,478)
	$215,960	$ 77,877	$146,439

Average wellhead prices in effect at December 31, 2007, 2006 and 2005 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows:

	2007	2006	2005
Oil (per Bbl)	$93.30	$58.05	$56.50
Natural gas liquids (per Bbl)	$60.09	$30.55	$ —
Gas (per Mcf)	$ 8.10	$ 6.55	$ 9.20

13. Supplementary Data

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

	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	(2,157)	(1,108)	(998)	(956)
Realized gain on commodity derivates	1,409	1,080	88	2,155
Change in fair value of 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	(1,047)	(1,058)	(984)	(725)
Realized gain on commodity derivatives	2,012	1,126	1,660	1,424
Change in fair value of 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

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]
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

GLENN W. REED
Senior Vice President – Operations

RALPH P. MANOUSHAGIAN
Senior Vice President – Land

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

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