ENCORE ACQUISITION CO
Form 10-K
March 07, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2005

Encore Acquisition Company
(Exact name of registrant as specified in its charter)

Delaware	**001-16295**	**75-2759650**
(State or other jurisdiction of incorporation)	*(Commission File Number)*	*(IRS Employer Identification No.)*

777 Main Street, Suite 1400, Fort Worth, Texas	**76102**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(817) 877-9955
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

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 þ No o

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

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 þ No o

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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Exchange Act Rule 12b-2 of the Act).

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

Aggregate market value of the voting and non-voting common stock held by non-affiliates of the Registrant as of June 30, 2005 (the last business day of Registrant s most recently completed second fiscal quarter)	$	1,248,081,269
Number of shares of Common Stock, $0.01 par value, outstanding as of March 3, 2006		49,768,854

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the Registrant s 2006 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

ENCORE ACQUISITION COMPANY
2005 ANNUAL REPORT ON FORM 10-K
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This annual report on Form 10-K (the Report) contains forward-looking statements, which give our current expectations and forecasts of future events. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by or on behalf of Encore Acquisition Company or its subsidiaries. See Item 1A. Risk Factors for a description of various factors that could materially affect the ability of Encore Acquisition Company to achieve the anticipated results described in the forward looking statements. Certain terms commonly used in the oil and natural gas industry and in this Report are defined at the end of Item 7A, beginning on page 61, under the caption Glossary of Oil and Natural Gas Terms. In addition, all production and reserve volumes disclosed in this Report represent amounts net to Encore Acquisition Company.

PART I

Items 1 and 2. *Business and Properties*

General

Our Business. We are a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since our inception in 1998, we have sought to acquire high quality assets with potential for upside through low-risk development drilling projects. Our properties and our oil and natural gas reserves are located in four core areas:

- the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota;
- the Permian Basin of West Texas and Southeastern New Mexico;
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of north Texas; and
- the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana and North Dakota, and the Paradox Basin of southeastern Utah.

Proved Reserves. Our estimated total proved reserves at December 31, 2005 were 148.4 MMBls of oil and 283.9 Bcf of natural gas, based on December 31, 2005 prices of $61.04 per Bbl for oil and $9.44 per Mcf of natural gas. On a barrel of oil equivalent basis, our proved reserves were 196 MMBOE at December 31, 2005, a 13% increase from proved reserves of 173 MMBOE at December 31, 2004.

Most Valuable Asset. The CCA represented 60% of our total proved reserves as of December 31, 2005. The CCA is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future exploitation of and production from this property through primary, secondary, and tertiary recovery techniques.

Recent Acquisitions.

Mid-Continent and Permian Basin Acquisition. On November 30, 2005, we completed the acquisition of oil and natural gas producing properties from Kerr-McGee Corporation for a total purchase price of $101.4 million. The properties are located in the Levelland-Slaughter, Howard Glasscock, Nolley-McFarland, and Hutex fields in West Texas and the Oakdale, Calumet, and Rush Springs fields in western Oklahoma. Total proved reserves are estimated to be approximately 94% oil and 69% proved developed producing. Operating results for these properties are included in our Consolidated Statement of Operations for the month of December 2005.

Crusader Energy Corporation. On October 14, 2005, we purchased all of the outstanding capital stock of Crusader Energy Corporation (Crusader), a privately held, independent oil and natural gas company, for a total purchase price of $109.7 million, which includes cash paid to Crusader s former shareholders of $79.2 million, the repayment of $29.7 million of Crusader s debt, and transaction costs totaling $0.8 million.

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The acquired properties are located primarily in the western Anadarko Basin and the Golden Trend area of Oklahoma. Total proved reserves are estimated to be approximately 78% natural gas and 72% proved developed producing. Crusader s operating results are included in our Consolidated Statement of Operations for the period from October through December 2005.

Drilling. In 2005, we drilled 160 gross operated productive wells and participated in drilling another 116 gross non-operated productive wells for a total of 276 gross productive wells for the year. On a net basis, we drilled 151.9 operated productive wells and participated in 14.6 non-operated productive wells in 2005. We also drilled 51 (44.1 net) non-productive wells in 2005, of which 47 (41.9 net) were exploratory wells. We invested $326.5 million in development and exploration activities, of which $8.7 million related to non-productive wells.

Oil and Natural Gas Reserve Replacement During 2005, we added 33.0 MMBOE of oil and natural gas reserves, which replaced 318% of the 10.4 MMBOE we produced in 2005. Our three year average reserve replacement ratio is 345%. The following table sets forth our calculation of our 2005, 2004, 2003, and three year average reserve replacement ratios (in thousands of BOE except percentages):

	Year Ended December 31,			
	2005	**2004**	**2003**	**Three Year Average**
Acquisition Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	14,796	22,239	6,257	14,431
Divided by:				
Production	10,381	9,027	8,110	9,173
Acquisition reserve replacement ratio	142%	246%	77%	157%
Development Reserve Replacement Ratio				
Changes in Proved Reserves:				
Extensions and discoveries	7,459	8,768	5,182	7,136
Improved recovery	11,699	11,812	12,744	12,085
Revisions of estimates	(928)	(1,629)	(3,493)	(2,017)
Total development program	18,230	18,951	14,433	17,204
Divided by:				
Production	10,381	9,027	8,110	9,173
Development reserve replacement ratio	176%	210%	178%	188%
Total Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	14,796	22,239	6,257	14,431
Extensions and discoveries	7,459	8,768	5,182	7,136
Improved recovery	11,699	11,812	12,744	12,085
Revisions of estimates	(928)	(1,629)	(3,493)	(2,017)
Total reserve additions	33,026	41,190	20,690	31,635
Divided by:				
Production	10,381	9,027	8,110	9,173

Total reserve replacement ratio	318%	456%	255%	345%

For the three years ended December 31, 2005, we have invested $542.8 million in acquiring producing oil and natural gas properties, and we have invested an incremental $613.7 million on development, exploitation, and exploration of our properties.

Given the inherent decline of reserves resulting from production, it is important for an exploration and production company to demonstrate a long-term trend of more than offsetting produced volumes with new reserves that will provide for future production. Management uses the reserve replacement ratio, as defined above, as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production. Management believes that reserve replacement is relevant and useful information that is commonly used by analysts, investors and other interested parties in the oil and gas industry as a means of evaluating the operational performance and prospects of entities engaged in the production and sale of depleting natural resources. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. The ratio does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop.

Business Strategies

Our primary business objective is to maximize shareholder value by executing the following strategies:

Maintain an active drilling and workover program. Our technological expertise, combined with our proficient field operations and reservoir engineering, has allowed us to increase production and reserves on our properties through development and exploitation drilling, workovers, and recompletions. Our plan is to maintain an inventory of low-risk exploitation and development projects that provide us ongoing drilling activity. Each year, we budget a portion of internally generated cash flow for secondary and tertiary recovery projects whose results will not be seen until future years.

Maximize existing reserves and production through high-pressure air injection. In addition to conventional development programs, we utilize high-pressure air injection techniques on the CCA properties to enhance our growth. High-pressure air injection (HPAI) involves using compressors to inject air into producing oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production. We believe that the HPAI programs on our CCA properties will generate a higher rate of return than other tertiary processes and can be applied throughout our CCA properties.

Utilize other improved recovery techniques to maximize existing reserves and production. In addition to our HPAI programs, we use secondary and other tertiary recovery techniques to increase production and proved reserves on existing properties. Throughout our CCA properties and Permian Basin properties, we have successfully used waterflood enhancement programs to increase production. Waterflood enhancement is a secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells. In certain properties in the Rockies, a similar tertiary recovery technique involving CO_2 has added approximately 1.5 million BOE of proved reserves. We believe that these other improved recovery techniques will continue to be a significant growth area for us.

Expand our reserves, production, and drilling inventory through a disciplined acquisition program. Using our experience, we have developed and refined an acquisition program designed to increase our reserves and to complement our core properties, while providing upside potential. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target and evaluate attractive acquisition opportunities. Following an acquisition, our technical professionals seek to enhance the value of the new assets through a proven development and exploitation program. We will continue to evaluate acquisition opportunities in 2006 with the same disciplined commitment to acquire assets that fit our portfolio and create value for our shareholders.

Explore for reserves. With the current commodity price environment, we believe exploration programs can provide a rate of return comparable to property acquisitions in certain areas. We seek to acquire undeveloped acreage and/or enter into drilling arrangements to explore in areas that complement our portfolio of properties. In keeping with our exploitation focus, the exploration projects are expected to set up multi-well exploitation projects if successful.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2005, we operated properties representing approximately 85% of our proved reserves, which allows us to control capital allocation, operate in a safe manner, and control timing of investments.

Challenges to Implementing Our Strategy. We face a number of challenges to implementing our strategy and achieving our goals. Our primary challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our drilling inventory. Changing commodity prices affect the rate of return on a property acquisition, and the amount of our internally generated cash flow, and, in turn, can affect our capital budget. In addition to the changing commodity price risk, we face strong competition from independents and major oil companies. For more information on the challenges to implementing our strategy and achieving our goals, please read Item 1A. Risk Factors beginning on page 16.

Operations

We act as operator of properties representing approximately 85% of our proved reserves at December 31, 2005. As operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities of these properties. We also own properties that are operated by third parties, and, as working interest owners in those properties, we are required to pay our share of operating, exploitation and development costs. See Properties Nature of Our Ownership Interests on page 11. During the years ended December 31, 2005, 2004, and 2003, our approximate costs for development activities on non-operated properties were $28.2 million, $10.9 million, and $5.4 million, respectively. We also own royalty interests in wells operated by third parties that are not burdened by lease operations expense or capital costs; however, we have little control over the implementation of projects on these properties.

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Production and Price History

The following table sets forth information regarding net production of oil and natural gas, certain price information, including the effects of hedging, and average costs per BOE for each of the periods indicated:

	As of December 31,		
	2005	2004	2003
Production:			
Oil (MBbls)	6,871	6,679	6,601
Natural gas (MMcf)	21,059	14,089	9,051
Combined (MBOE)	10,381	9,027	8,110
Average Daily Production:			
Oil (Bbls/day)	18,826	18,249	18,085
Natural gas (Mcf/day)	57,696	38,493	24,798
Combined (BOE/day)	28,442	24,665	22,218
Average Prices:			
Oil (per Bbl)	$ 44.82	$ 33.04	$ 26.72
Natural gas (per Mcf)	7.09	5.53	4.83
Combined (per BOE)	44.05	33.07	27.14
Average Costs per BOE:			
Lease operations expense	$ 6.59	$ 5.22	$ 4.67
Production, ad valorem, and severance taxes	4.39	3.36	2.71
Depletion, depreciation and amortization	8.25	5.38	4.13
Exploration	1.39	0.43	
General and administrative (excluding non-cash stock based compensation)	1.42	1.22	1.07
Other operating expense	0.91	0.56	0.43

Producing Wells

The following table sets forth information at December 31, 2005 relating to the producing wells in which we owned a working interest as of that date. We also held royalty interests in units and acreage beyond the wells in which we have a working interest. Wells are classified as oil or natural gas according to their predominant production stream. Gross wells are the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest. As of December 31, 2005, we owned a working interest in 5,332 gross wells.

	Oil Wells			Natural Gas Wells		
	Gross Wells(1)	Net Wells	Average Working Interest	Gross Wells(1)	Net Wells	Average Working Interest
Cedar Creek Anticline	756	673	89%	18	6	31%
Permian Basin	1,811	486	27%	483	223	46%
Rockies	605	319	53%	15	14	91%
Mid-Continent	366	174	48%	1,278	315	25%
Total	3,538	1,652	47%	1,794	558	31%

(1) Our total wells include 2,449 operated wells and 2,883 non-operated wells. At December 31, 2005, 26 of our wells have multiple completions.

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Acreage

The following table sets forth information at December 31, 2005 relating to our acreage holdings. Developed acreage is assigned to producing wells. Undeveloped acreage is held under lease, permit, contract, or option that is not in a spacing unit for a producing well, including leasehold interests identified for exploitation or exploratory drilling. Our undeveloped acreage is concentrated in the Rockies region, which represents 71% of our total undeveloped acreage. These leases expire at various dates ranging from 2006 to 2029, with leases representing $1.6 million of cost set to expire in 2006 if not developed.

	Gross Acreage	Net Acreage
Cedar Creek Anticline:		
Developed	111,189	103,333
Undeveloped	83,242	61,204
	194,431	164,537
West Texas and New Mexico:		
Developed	63,772	38,856
Undeveloped	13,567	12,842
	77,339	51,698
Rockies:		
Developed	58,880	35,778
Undeveloped	407,181	340,332
	466,061	376,110
Mid-Continent:		
Developed	379,148	96,895
Undeveloped	70,641	20,378
	449,789	117,273
Total:		
Developed	612,989	274,862
Undeveloped	574,631	434,756
	1,187,620	709,618

Drilling Results

The following table sets forth information with respect to wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found, or economic value. Development wells are wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. Exploratory wells are wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir. Productive wells are those that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

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	Year Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	242	145	203	135	137	103
Dry holes	4	2	1	1	1	1
	246	147	204	136	138	104
Exploratory Wells:						
Productive	34	22	32	30		
Dry holes	47	42	4	4		
	81	64	36	34		
All Wells Drilled:						
Productive	276	167	235	165	137	103
Dry holes	51	44	5	5	1	1
Total	327	211	240	170	138	104

Present Activities

As of December 31, 2005 we had a total of 14 gross (8.4 net) wells that had been spud and were in varying stages of drilling operations, of which 9 gross (4.4 net) wells were development wells. Also, there were 50 gross (33.9 net) wells that had reached total depth and were in varying stages of completion pending first production, of which 10 gross (8.0 net) wells were exploratory wells.

High-pressure air injection in the Little Beaver unit of the CCA was initiated in late 2003, and full implementation of the project was completed in the fourth quarter of 2004. We continue to see positive production response in line with expectations, with an increase of 800 barrels of oil per day over the expected production decline prior to the initiation of the project.

In the Pennel unit of the CCA, where we have been operating a successful HPAI appraisal project (Phase 1) for nearly three years, we completed the Phase 2 portion of the project and are currently expanding to Phase 3. In April 2005, we installed a new HPAI facility capable of injecting 60 million cubic feet per day of air into the Pennel and Coral Creek units of the CCA, giving us the capacity to complete the development of these units. The Pennel Field is responding to the air injection as expected, with an increase of 400 barrels of oil per day over the expected production decline prior to the initiation of the project.

Delivery Commitments and Marketing

Our oil and natural gas production is principally sold to end users, marketers, refiners, and other purchasers having access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. While we typically market our oil and natural gas production for a term of a year or less, we entered into an agreement in 2004 to sell at least 2,500 barrels of oil per day at a floating market price through 2009.

For the fiscal year 2005, our largest purchasers included Shell, Eighty-Eight Oil, BP, and Chevron, which respectively accounted for 26%, 16%, 14%, and 10% of total oil and natural gas sales. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted. Management believes that the loss of any one purchaser would not have a material adverse effect on our ability to market our oil and natural gas production.

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The sale of our CCA oil production is dependent on transportation through Butte Pipeline to markets in the Guernsey, Wyoming area. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and subject to apportionment since December 2005, we have been able to move our produced volumes through Platte Pipeline. However, further restrictions on the available capacity to transport oil through Platte Pipeline or other pipelines could have a material adverse effect on price received, production volumes, and revenues.

We expect the differential between the NYMEX price of crude oil and the wellhead price we receive to widen in the first half of 2006 as compared to the fourth quarter of 2005. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited takeaway capacity from the Rocky Mountain area, have gradually widened this differential. A particularly active turnaround season on the part of Rocky Mountain area refiners in the first quarter of 2006 has led to a further widening of the differential. We cannot accurately predict crude oil differentials for subsequent quarters. Natural gas differentials are expected to remain approximately constant in the first half of 2006 as compared to the fourth quarter of 2005. Increases in the differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows.

Competition

We compete with major and independent oil and natural gas companies. Some of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial, and local laws and regulations more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies, and consummate transactions in this highly competitive environment.

Federal and State Regulations

Compliance with applicable federal and state regulations is often difficult and costly, and non-compliance may result in substantial penalties. The following are some specific regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Regulation of Natural Gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates and various other matters, by the Federal Energy Regulatory Commission (FERC). Federal wellhead price controls on all domestic natural gas were terminated on January 1, 1993 and none of our natural gas sales are currently subject to FERC regulation. We cannot predict the impact of future government regulation on any natural gas operations.

Although FERC s regulations should generally facilitate the transportation of natural gas produced from our properties and the direct access to end-user markets, the future impact of these regulations on marketing our production or on our natural gas transportation business cannot be predicted. We do not believe, however, that we will be affected differently than competing producers and marketers.

Federal Regulation of Oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. A significant part of our oil production is transported by pipeline. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. The United States Court of Appeals upheld FERC s orders in 1996. These rules have had little effect on our oil transportation cost.

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State Regulation. Oil and natural gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operations of wells, and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and natural gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled.

Federal, State or Native American Leases. Our operations on federal, state or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, Minerals Management Service and other agencies.

Environmental Regulations. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and natural gas exploration, development and production operations, and consequently may impact our operations and costs. Management believes that we are in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and we do not currently anticipate that future compliance will have a material adverse effect on our consolidated financial position, cash flows, or results of operations.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, and other potential events that can adversely affect our operations. Any of these problems could adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation, or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

We had 205 employees as of December 31, 2005, 75 of which were field personnel. None of the employees are represented by any union. We consider our relations with our employees to be good.

Principal Executive Office

We are a Delaware corporation with our headquarters in Texas. Our principal executive offices are located at 777 Main Street, Suite 1400, Fort Worth, Texas 76102. Our main telephone number is (817) 877-9955.

Available Information

We make available electronically, free of charge through our website (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and other items filed with the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with or furnish such material to the SEC. In addition, 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. The SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers, like us, that file electronically with the SEC.

We have adopted a code of business conduct and ethics that applies to all directors, officers, and employees, including our principal executive officer and senior financial officers. The code of business conduct and ethics is available on our Internet website (www.encoreacq.com). In the event that we make changes in, or provide waivers from, the provisions of this code of business conduct and ethics that the SEC or the New York Stock Exchange (NYSE) require us to disclose, we intend to disclose these events on our website.

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this Report. In 2005, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE s Listed Company Manual. In 2006, we expect to submit this certification to the NYSE after the annual meeting of stockholders.

Our board of directors currently has three standing committees: (1) audit, (2) compensation, and (3) nominating and corporate governance. The charters of our board committees are available on our website. Copies of the code of business conduct and ethics and board committee charters are also available in print upon written request to the Corporate Secretary, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

The information on our website or any other website is not incorporated by reference into this Report.

Financial information about our business for the three years ended December 31, 2005 can be found in our consolidated financial statements and the accompanying notes included in Item 8 of this Report.

Properties

Nature of Our Ownership Interests

The following table sets forth the net production, proved reserve quantities, and PV-10 values of our properties in our principal areas of operation:

	Net Production 2005				Proved Reserve Quantities at December 31, 2005			PV-10 at December 31, 2005	
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent	Oil (MBbls)	Natural Gas (MMcf)	Total MBOE	Amount(1) (In thousands)	Percent
Cedar Creek Anticline	4,868	1,237	5,074	49%	113,701	16,870	116,513	$ 1,424,876	53%
Permian Basin	1,138	6,261	2,182	21%	21,958	85,921	36,278	573,476	22%
Mid-Continent	179	13,127	2,367	23%	3,938	177,698	33,554	536,668	20%
Rockies	686	434	758	7%	8,790	3,376	9,353	143,953	5%
Total	6,871	21,059	10,381	100%	148,387	283,865	195,698	$ 2,678,973	100%

(1) Calculated as the pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs; using prices and costs as of the date of estimation without future escalation; without giving effect to hedging activities, and non-property related expenses such as general and administrative expenses, debt service, and depletion, depreciation, and amortization; and discounted using an annual discount rate of 10%. Giving effect to hedging transactions, our PV-10 value would have been decreased by $128.4 million at December 31, 2005. The Standardized Measure at

December 31, 2005 is $1.9 billion. Standardized Measure differs from PV-10 by $760.5 million because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

The estimates of our proved oil and natural gas reserves are based on estimates prepared by Miller and Lents, Ltd., independent petroleum engineers. Guidelines established by the SEC regarding the present value of future net revenues were used to prepare these reserve estimates. Reserve engineering is a

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subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by petroleum engineers. In addition, the results of drilling, testing and production activities may require revisions of estimates that were made previously. Accordingly, estimates of reserves and their value are inherently imprecise and are subject to constant revision and change, and they should not be construed as representing the actual quantities of future production or cash flows to be realized from oil and natural gas properties or the fair market value of such properties.

During the calendar year 2005, we filed estimates of oil and natural gas reserves at December 31, 2004 with the U.S. Department of Energy on Form EIA-23. As required for the EIA-23, the filing reflected only production that comes from our operated wells at year end, and is reported on a gross basis. Those estimates came directly from our reserve report prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Cedar Creek Anticline Properties Montana and North Dakota

Our initial purchase of interests in the CCA was on June 1, 1999, and we have subsequently acquired additional working interests from various owners. Presently, we operate approximately 99.7% of our CCA properties with an average working interest of approximately 89.3%. The average daily production from our CCA properties during 2005 was 13,902 BOE per day.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. Our acreage is concentrated on the two to six mile wide crest of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 120 continuous miles along the crest of the CCA across five counties in two states. Primary producing reservoirs are the Red River, Stony Mountain, Interlake, and Lodgepole formations at depths of between 7,000 feet and 9,000 feet.

Since taking over operations, along with subsequent additional acquired interests, we have increased production by 80.3% on the CCA from 7,807 BOE per day (average for June 1999) to 14,078 BOE per day (average for the fourth quarter of 2005). We have accomplished ongoing production growth through a combination of:

- additional acquisition of interests;
- effective management of the existing wellbores;
- the addition of strategically positioned new horizontal and vertical wellbores;
- the application of horizontal re-entry drilling in existing wellbores;
- waterflood enhancements; and
- implementation of our high-pressure air injection program.

In 2005, we drilled 63 gross wells on the CCA, of which 33 were horizontal re-entry wells that reestablished production from non-producing wells, added additional barrels from existing producing wells and serve as injection wells for secondary and tertiary recovery projects. Including our HPAI project, we invested $121.7 million, $116.5 million, and $77.6 million in capital projects on the CCA during 2005, 2004, and 2003, respectively.

Our outlook for sustained CCA production growth remains strong. We plan to continue the development of the reserve base through ongoing drilling and exploitation efforts on these properties. We believe that HPAI continues to be our most significant source of sustained production growth on the CCA.

The CCA represents 60% of our total proved reserves as of December 31, 2005. The CCA represents our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future conventional exploitation, production, and success of HPAI projects on these properties.

High-pressure air injection. In 2005, we continued our high-pressure air injection program at the CCA. High-pressure air injection is a tertiary recovery technique that involves using compressors to inject air into oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

In 2002, we initiated a HPAI project that injects air into the Red River U4 zone in the Pennel unit of the CCA. The Red River U4 zone is the same zone where high-pressure air injection has been successfully implemented by other operators in adjacent areas on the CCA. We have seen positive results from this high-pressure air injection project at the Pennel and the Little Beaver units. Based on these results, we are in the process of expanding high pressure air injection to other areas in the CCA. We believe that high-pressure air injection technology can be applied throughout the CCA and that it may yield significant new reserves. We believe that the high-pressure air injection will generate a higher rate of return than other tertiary processes on the CCA.

In the Pennel unit, we have completed Phase 1 and Phase 2 of the HPAI project and are currently expanding to Phase 3. In April 2005, we installed a new HPAI facility capable of injecting 60 million cubic feet per day of air into the Pennel and Coral Creek units of the CCA, giving us the capacity to complete the development of these units. The Pennel unit is responding to the air injection as expected, with an increase of 400 barrels of oil per day over the forecasted production decline prior to the initiation of the project.

High-pressure air injection in the Little Beaver unit of the CCA was initiated in late 2003, and full implementation of the project was completed in the fourth quarter of 2004. Through 2005, the program has added proved reserves of approximately 15 million BOE to the Little Beaver unit. We continue to see positive production response in line with expectations, with an increase of 800 barrels of oil per day over the forecasted production decline prior to the initiation of the project.

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We believe that much of our acreage in the CCA has potential opportunities for utilizing HPAI recovery techniques at economic rates of return. We continue to evaluate and perform engineering studies on these projects. Over the next several years, we plan to implement these development projects initially in the Red River U4 zone of the CCA. Additionally, we have other zones in the CCA that currently produce oil and may provide additional HPAI opportunities. We believe these zones can be most economically evaluated for HPAI opportunities after assessing HPAI in the Red River U4 zone.

Net Profits Interests. A major portion of our acreage position in the CCA is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the NPIs and will have an inverse effect on our reported reserves and production. For the years ended December 31, 2005, 2004, and 2003, we reduced revenue for the payments of the net profits interests by $21.2 million, $12.6 million, and $5.8 million, respectively.

Permian Basin Properties West Texas and New Mexico

Our Permian Basin properties include seventeen operated fields, including East Cowden Grayburg Unit, Furhman-Mascho, Crockett County, Sand Hills, Howard Glasscock, Nolley, Deep Rock and others; and seven non-operated fields. Production from the central portion of the Permian Basin comes from multiple reservoirs including the Grayburg, San Andres, Glorietta, Clearfork, Wolfcamp, and Pennsylvanian zones. Production from the southern portion of the Permian Basin comes mainly from the Canyon and Strawn Formations with multiple pay intervals.

Continued development opportunities remain on these properties. During 2005, we drilled 80 gross wells on the Permian properties primarily in the Sand Hills, Furhman-Mascho, and Crockett County fields. Average daily production in the fourth quarter of 2005 was 5,806 BOE per day. We believe these properties will be an area of growth over the next several years.

During 2005, we invested approximately $44.0 million of development capital on our Permian Basin properties. In the fourth quarter of 2005, we acquired additional oil and natural gas producing properties in the Permian Basin from Kerr-McGee Corporation.

Mid-Continent Properties Oklahoma, Arkansas, East Texas, North Texas, Kansas, and North Louisiana

Oklahoma, Arkansas, North Texas, and Kansas

We own various interests, including operated, non-operated, royalty and mineral interests, on properties located in the Anadarko Basin of western Oklahoma and the Arkoma Basin of eastern Oklahoma, and eastern Arkansas. These properties produce primarily natural gas, and to a lesser extent oil, from various horizons. We also have operated interests in properties producing from the Barnett Shale in north Texas, and interests in properties in the Hugoton Basin in Kansas.

Average daily production for the Oklahoma, Arkansas, North Texas, and Kansas region increased 124% from 11,284 Mcfe per day in the fourth quarter of 2004 to 25,317 Mcfe per day for the fourth quarter of 2005.

During 2005, we invested $52.2 million of development and exploration capital in these properties. In the fourth quarter of 2005, we acquired additional Mid-Continent properties through the acquisition of

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Crusader Energy Corporation and the purchase of oil and natural gas producing properties from Kerr-McGee Corporation.

North Louisiana Salt Basin and East Texas Basin

The North Louisiana Salt Basin and East Texas Basin properties consist of operated working interests, non-operated working interests, and undeveloped leases acquired primarily in the Elm Grove and Overton acquisitions in 2004. Our interests acquired in the Elm Grove acquisition are located in the Elm Grove Field in Bossier Parish, Louisiana, and include non-operated working interests ranging from 1% to 47% across 1,800 net acres in 15 sections.

The Overton Field assets are in the same core area as our interests in Elm Grove Field and have similar geology. The properties are producing primarily from multiple tight sandstone reservoirs in the Travis Peak and Lower Cotton Valley formations at depths ranging between 8,000 and 11,500 feet. Estimated proved reserves are approximately 94% natural gas and the properties are 100% operated by us.

During 2005, we drilled 72 gross wells in the Elm Grove and Overton fields and invested approximately $91.4 million of capital to develop these properties. Average daily production for this region increased 68% from 15,366 Mcfe per day in the fourth quarter of 2004 to 25,800 Mcfe per day for the fourth quarter of 2005. We believe these properties continue to be an area of growth for us.

Rocky Mountain Properties North Dakota, Montana, and Utah

Williston Basin North Dakota and Montana

The Williston Basin properties consist of working and overriding royalty interests in several geographically concentrated fields. The properties are located in the Williston Basin in western North Dakota and eastern Montana, near our CCA properties. The properties produce exclusively from the Mississippian-aged Lodgepole Formation, and the Eland Unit is the largest accumulation in the trend. The average daily production from the Williston Basin properties was 1,191 BOE for the fourth quarter of 2005.

In 2005, we acquired additional working interests in the Williston Basin for approximately $28.6 million. Production from the properties, which are concentrated primarily in the Crane Field in Montana and the Tracy Mountain Field in North Dakota, is approximately 94% oil and 77% operated.

Bell Creek Montana

The Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate the seven production units that comprise the Bell Creek properties, each with a 100% working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces 100% oil. We invested $7.5 million of capital in these properties in 2005. The average daily production from the Bell Creek properties was 386 BOE per day during the fourth quarter of 2005. In the fall of 2005, we initiated a small field test of new technology called Microbial Enhanced Oil Recovery (MEOR) in conjunction with the State of Montana, MSE Technology Applications Center for Innovations and Montana Tech. This process may enhance oil production by creating a natural Bio-film which diverts injected water towards un-swept oil. We have not yet been able to ascertain the performance of this project but continue to monitor its progress.

Paradox Basin Utah

The Paradox Basin properties, located in southeast Utah s Paradox Basin, are divided between two prolific oil producing units: the Ratherford Unit operated by ExxonMobil and the Aneth Unit operated by Resolute Natural Resources Company. Our average net production from the properties for the fourth quarter of 2005 was approximately 660 BOE per day. We believe these properties have potential horizontal redevelopment, secondary development, and tertiary recovery potential. During 2005, we added proved reserves of 1.5 MMBOE from a CO_2 flood tertiary recovery program in the Aneth Unit. Our development capital for these properties was $0.7 million during 2005.

Shallow Gas Montana

In 2004, we began a project to explore for natural gas in the shallow zones of our acreage in north central Montana. The primary producing horizon in this area is the Eagle Sandstone, which produces from reservoir depths between 800 feet and 1,200 feet. This Eagle Sandstone has produced large quantities of natural gas to date from numerous fields across northern Montana. We invested $5.2 million of capital during 2005 to drill a total of 37 exploratory wells, all of which were subsequently expensed as dry holes in 2005. In addition, 8 additional exploratory wells drilled in 2004 were expensed as dry holes in 2005. We have 365,954 undeveloped leasehold acres with an average lease term of approximately 7.5 years. We plan to continue to drill and analyze this acreage in 2006 and future years.

The success rate of any future exploratory wells that we may drill in this area will be lower than our historical company average. Additionally, there can be no guarantee that reserves will be found in a sufficient quantity as to make them economically producible. If reserves are not found in a quantity that would make them economically producible, all costs to drill the well, as well as any related undeveloped leasehold costs associated with the lease on which the well was drilled, would be expensed in the period in which the determination was made.

Title to Properties

We believe that our title to our oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and natural gas industry.

Our properties are subject, in one degree or another, to one or more of the following:

- royalties, overriding royalties, net profit interests, and other burdens under oil and natural gas leases;

- contractual obligations, including, in some cases, development obligations arising under operating agreements, farmout agreements, production sales contracts, and other agreements that may affect the properties or their titles;

- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors, and contractual liens under operating agreements;

- pooling, unitization and communitization agreements, declarations, and orders; and

- easements, restrictions, rights-of-way, and other matters that commonly affect property.

We believe that the burdens and obligations affecting our properties do not in the aggregate materially interfere with the use of the properties. As indicated under Net Profits Interests above, a major portion of our acreage position in the CCA, our primary asset, is subject to net profits interests.

Item 1A. ***Risk Factors***

You should read carefully the following factors and all other information contained in this Report. If any of the risks and uncertainties described below or elsewhere in this Report actually occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common stock could decline, and an investor may lose all or part of his investment.

Oil and natural gas prices are volatile and sustained periods of low prices could materially and adversely affect our financial condition, results of operations, and cash flows.

Historically, the markets for oil and natural gas have been volatile, and these markets are likely to continue to be volatile in the future. Our revenues, profitability and future growth depend substantially on prevailing oil and natural gas prices. Lower oil and natural gas prices may reduce the amount of oil and natural gas that we can economically produce. Prevailing oil and natural gas prices also affect the amount of internally generated cash flow available for repayment of indebtedness and capital expenditures. In addition, the amount we can borrow under our revolving credit facility is subject to periodic redetermination based in part on changing expectations of future oil and natural gas prices.

The factors that can cause oil and natural gas price volatility include:

- the supply of domestic and foreign oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- political instability or armed conflict in oil or natural gas producing regions;
- the level of consumer demand;
- the proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- refinery demands and customer preferences for different grades of crude oil;
- weather conditions;
- the price and availability of alternative fuels and technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- domestic political developments; and
- worldwide economic conditions.

In addition, the prices that we receive for our oil and natural gas production sometimes trade at a discount to the relevant benchmark prices, such as NYMEX. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited takeaway capacity from the Rocky Mountain area, have gradually widened this differential. A particularly active turnaround season on the part of Rocky Mountain area refiners in the first quarter of 2006 has led to a further widening of the differential. We cannot accurately predict future differentials.

The volatile nature of markets for oil and natural gas makes it difficult to reliably estimate future prices. Any decline in oil and natural gas prices adversely affects our financial condition. If oil or natural gas prices decline significantly or if our wellhead price is lowered materially in comparison to the NYMEX price for a sustained period of time, we may, among other things, be unable to meet our financial obligations, make planned expenditures or raise additional capital.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Estimating quantities of proved oil and natural gas reserves is a complex process that requires interpretations of available technical data and numerous assumptions, including certain economic assumptions. Any significant inaccuracies in these interpretations or assumptions or changes in conditions could cause the quantities and net present value of our reserves to be overstated.

To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows, we must analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs. Actual results most likely will vary from our estimates. Any significant variance could reduce the estimated quantities and present value of our reserves.

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You should not assume that the present value of future net cash flows from our proved reserves referred to in this Report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate.

The results of high pressure air injection techniques are uncertain.

We utilize high pressure air injection, or HPAI, techniques on some of our properties and plan to use the techniques in the future on a substantial portion of our properties, including our CCA properties. The additional production and reserves attributable to our use of the techniques, if any, are inherently difficult to predict. If our HPAI programs do not allow for the extraction of residual hydrocarbons in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

We may be required to take write downs.

We may be required to write down the carrying value of our oil and natural gas properties if (1) future estimated oil and natural gas prices are low, (2) we have substantial downward adjustments to our estimated proved reserves, (3) our estimates of operating expenses or development costs increase substantially, or (4) we experience poor performance from our development and exploitation activities. We capitalize the costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. We review the carrying value of our properties quarterly, based on changes in expectations of future oil and natural gas prices, expenses and tax rates. Once incurred, a write down of oil and natural gas properties is not reversible at a later date even if oil or gas prices increase.

Our acquisition strategy subjects us to numerous risks that could adversely affect our results of operations.

Acquisitions are an essential part of our growth strategy, and our ability to acquire additional properties on favorable terms is important to our long-term growth. Depending on conditions in the acquisition market, it may be difficult or impossible for us to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. Even if we are able to identify suitable acquisition opportunities, our acquisition strategy depends upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results. Furthermore, our financial position and results of operations may fluctuate significantly from period to period based on whether significant acquisitions are completed in particular periods. Competition for acquisitions is intense and may increase the cost of, or cause us to refrain from, completing acquisitions.

The failure to properly manage growth through acquisitions could adversely affect our results of operations.

Growing through acquisitions and managing that growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. Pursuing and integrating acquisitions involves a number of risks, including:

- diversion of management attention from existing operations;
- unexpected losses of key employees, customers and suppliers of the acquired business;
- conforming the financial, technological and management standards, processes, procedures and controls of the acquired business with those of our existing operations; and
- increasing the scope, geographic diversity and complexity of our operations.

The process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

A substantial portion of our producing properties is located in one geographic area.

We have extensive operations in the Williston Basin of Montana and North Dakota. As of December 31, 2005, our CCA properties in the Williston Basin represented approximately 60% of our proved reserves and 49% of our 2005 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the Williston Basin could materially reduce our earnings and cash flow.

Derivative instruments expose us to risks of financial loss in a variety of circumstances.

We use derivative instruments in an effort to reduce our exposure to fluctuations in the prices of oil and natural gas and to reduce our cash outflows related to interest. Our derivative instruments expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty to our derivative instruments is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

Derivative instruments may limit our ability to realize increased revenue from increases in the prices for oil and natural gas.

We adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), on January 1, 2001. SFAS 133 generally requires us to record each hedging transaction as an asset or liability measured at its fair value. Each quarter we must record changes in the fair value of our hedges, which could result in significant fluctuations in net income and stockholders equity from period to period.

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Fluctuations in the NYMEX price for oil or natural gas that do not coincide with changes in our wellhead price may preclude the use of hedge accounting and cause earnings volatility.

Many of our commodity derivative contracts are based on the NYMEX price for oil and natural gas. We have experienced increased ineffectiveness in our cash flow hedges, particularly those designated on our Rocky Mountain production, due to increasing differentials between our average oil wellhead price and the average NYMEX oil price. We expect those differentials to widen at least through the first half of 2006. Increasing differentials will result in additional ineffectiveness on some of our cash flow hedges. Additionally, if the correlation between changes in our average wellhead price and the average NYMEX oil price drops below a certain level, we would no longer be allowed to use hedge accounting for these cash flow hedges and would be required, instead, to use mark-to-market accounting. In such circumstances, any change in the mark-to-market value of our hedges would be recognized immediately in earnings as a non-cash charge and could cause significant earnings volatility.

The failure to replace our reserves could adversely affect our financial condition.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploitation, development, or exploration activities or acquire properties containing proved reserves, or both. We may not be able to find, develop or acquire additional reserves on an economic basis.

Substantial capital is required to replace and grow reserves. If lower oil and natural gas prices or operating difficulties result in our cash flow from operations being less than expected or limit on our ability to borrow under our revolving credit facility, we may be unable to expend the capital necessary to find, develop or acquire new oil and natural gas reserves.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Drilling oil and natural gas wells is a high-risk activity.

Drilling oil and natural gas wells involves numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. We often are uncertain as to the future cost or timing of drilling, completing and producing wells. We may not recover all or any portion of our investment in drilling oil and natural gas wells.

Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions or miscalculations, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with environmental and other governmental requirements and cost of, or shortages or delays in the availability of, drilling rigs, equipment and field personnel.

Our business involves many operating risks that can cause substantial losses; insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- explosions;
- formations with abnormal pressures;
- blowouts;
- collapses of wellbore, casing or other tubulars;
- failure of oilfield drilling and service tools;
- uncontrollable flows of oil, natural gas, formation water or drilling fluids;
- pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion;
- changes in below-ground pressure in a formation that causes surface collapse or cratering;
- pipeline ruptures or cement failures;
- environmental hazards, such as oil spills, natural gas leaks and discharges of toxic gases; and
- weather.

If any of these events occur, we could incur substantial losses as a result of injury or loss of life; damage to and destruction of property, natural resources and equipment; pollution and other environmental damage; regulatory investigations and penalties; suspension of our operations; and repair and remediation costs.

We do not maintain insurance against the loss of oil or natural gas reserves as a result of operating hazards, nor do we maintain business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. We may experience losses for uninsurable or uninsured risks or losses in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for oil and natural gas, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse affect on our business.

Our development, exploitation and exploration operations require substantial capital, and we may be unable to obtain needed financing on satisfactory terms.

We make and will continue to make substantial capital expenditures in development, exploitation and exploration projects. We intend to finance these capital expenditures through a combination of cash flow from operations and external financing arrangements. Additional financing sources may be required in the future to fund our capital expenditures. Financing may not continue to be available under existing or new financing arrangements, or on acceptable terms, if at all. If additional capital resources are not available, we may be forced to curtail our drilling and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of I. Jon Brumley, our Chairman of the Board, Jon S. Brumley, our Chief Executive Officer and President, and other key personnel. The loss of the services of Mr. I. Jon Brumley, Mr. Jon S. Brumley or other key personnel could adversely affect our business, and we do not have employment agreements with, and do not maintain key man insurance on the lives of, any of these persons.

Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense and the cost of attracting and retaining technical personnel has increased significantly in recent months. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed. Furthermore, escalating personnel costs could adversely effect our results of operations and financial condition.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production and could harm our business.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipelines, oil and natural gas gathering systems and processing facilities. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, 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. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity could reduce our ability to market our oil and natural gas production and harm our business.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation and production. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- acquiring desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production;
- integrating new technologies; and
- acquiring the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial, technological and other resources substantially greater than ours, which may adversely affect our ability to compete with these companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

We are subject to complex federal, state and local laws and regulations that could adversely affect our business.

Exploration, development, production and sale of oil and natural gas in North America are subject to extensive federal, state, provincial and local laws and regulations, including complex tax and environmental laws and regulations. We may be required to make large expenditures to comply with applicable laws and regulations, which could adversely affect our results of operations and financial condition. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection, reports concerning operations and taxation. Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, reclamation costs, remediation and clean-up costs and other environmental damages.

We do not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost, and we may need to expend significant financial and managerial resources to comply with environmental regulations and permitting requirements. We could incur substantial additional costs and liabilities in our oil and natural gas operations as a result of stricter environmental laws, regulations and enforcement policies.

Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties, suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

We have entered into, and may in the future enter into, long-term drilling and service contracts that may not be economical if oil and natural gas prices decline significantly.

The level of exploration and development activity in the oil and natural gas industry depends, in part, on prevailing commodity prices. In periods of comparatively high commodity prices, the level of exploration and development activity increases as projects that may have been uneconomical at lower commodity prices become financially more attractive at higher commodity prices. An increase in exploration and development activity results in increased demand for drilling rigs and other oilfield services, which often translates into higher costs and more stringent contract terms for oil and natural gas companies. In the current environment of comparatively high commodity prices, we have entered into, and may in the future enter into, long-term contracts for drilling rigs and other oilfield services. If commodity prices decline significantly, projects that may have been economical at higher prices may no longer provide satisfactory rates of return to warrant their continued development. Even if we elect to forgo certain projects, however, we may still be obligated under long-term contracts to pay for drilling rigs and other oilfield services at prices that do not justify their continued use or that significantly reduce our rates of return. In periods of declining commodity prices, long-term contracts for drilling rigs and oilfield services entered into during periods of comparatively high commodity prices could have a material adverse effect on our results of operations, financial condition, and cash flows.

We could incur substantial additional indebtedness, which could negatively impact our financial condition, results of operations and business prospects and prevent us from fulfilling our obligations under our outstanding debt.

As of December 31, 2005, we had total debt of $673.2 million and stockholders equity of $546.8 million. Together with our subsidiaries, we may incur substantially more debt in the future. Although our revolving credit facility, the indentures governing our 6$^1/4$%, 6%, and 7$^1/4$% notes contain restrictions on our incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with

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these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness. As of December 31, 2005, we had approximately $420.0 million of available borrowing capacity under our revolving credit facility, subject to specific requirements, including compliance with financial covenants.

Our debt level could have several important consequences to you, including:

- we may have difficulties borrowing money in the future for acquisitions, to meet our operating expenses or for other purposes;
- the amount of our interest expense may increase because certain of our borrowings are at variable rates of interest, which, if interest rates increase, could result in higher interest expense;
- we will need to use a portion of the money we earn to pay principal and interest on our debt which will reduce the amount of money we have to finance our operations and other business activities;
- we may be more vulnerable to economic downturns and adverse developments in our industry; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which are beyond our control. Our earnings may not be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity, which we may not be able to do on terms acceptable to us, if at all. Further, failing to comply with the financial and other restrictive covenants in our indebtedness could result in an event of default under such indebtedness, which could adversely affect our business, financial condition and results of operations.

Item 1B. *Unresolved Staff Comments*

There were no unresolved Securities and Exchange Commission staff comments as of December 31, 2005.

Item 3. *Legal Proceedings*

We are not currently a party to any material legal proceeding of which we are aware.

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

There were no matters submitted to stockholders during the quarter ended December 31, 2005.

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PART II

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

Our common stock, $0.01 par value, is listed on the NYSE under the symbol EAC. The following table sets forth quarterly high and low sales prices of our common stock for each quarterly period of 2005 and 2004, as adjusted retroactively to reflect a 3-for-2 stock split that occurred on July 12, 2005:

	High	Low
2005		
Quarter ended December 31	$ 39.37	$ 29.69
Quarter ended September 30	39.48	28.63
Quarter ended June 30	29.63	22.12
Quarter ended March 31	30.48	21.44
2004		
Quarter ended December 31	$ 24.59	$ 20.37
Quarter ended September 30	23.17	16.99
Quarter ended June 30	21.00	16.54
Quarter ended March 31	19.23	15.77

On March 3, 2006, the closing sales price of our common stock as reported by the NYSE was $32.08 per share. On March 3, 2006, we had approximately 262 shareholders of record.

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the fourth quarter of 2005:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
October		$		
November(a)	11,169	$ 33.56		
December		$		
Total	11,169	$ 33.56		

(a) We do not have a formal common stock repurchase program. During the quarter ended December 31, 2005, certain employees surrendered shares of common stock to pay income tax withholding obligations in conjunction with vesting of restricted shares under our 2000 Incentive Stock Plan.

Dividends

No dividends have been declared or paid on our common stock. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and plans for expansion. The declaration and payment of dividends is restricted by our existing credit agreement and the indentures governing our subordinated notes. Future debt agreements may also restrict our ability to pay dividends.

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

The following selected consolidated financial data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data (in thousands except per share and per unit data):

	Year Ended December 31,				
	2005	2004	2003	2002	2001
Consolidated Statement of Operations Data:					
Revenues:(1)					
Oil	$ 307,959	$ 220,649	$ 176,351	$ 134,854	$ 105,768
Natural gas	149,365	77,884	43,745	25,838	30,149
Total revenues	$ 457,324	$ 298,533	$ 220,096	$ 160,692	$ 135,917
Net income	$ 103,425(4)	$ 82,147	$ 63,641(2)	$ 37,685	$ 16,179(3)
Net income per common share:(5)					
Basic	$ 2.12	$ 1.74	$ 1.41	$ 0.84	$ 0.38
Diluted	2.09	1.72	1.40	0.83	0.38
Weighted average number of common shares outstanding:(5)					
Basic	48,682	47,090	45,153	45,047	43,077
Diluted	49,522	47,738	45,500	45,242	43,085
Consolidated Statement of Cash Flows Data:					
Cash provided by (used in):					
Operating activities	$ 292,269	$ 171,821	$ 123,818	$ 91,509	$ 80,212
Investing activities	(573,560)	(433,470)	(153,747)	(159,316)	(89,583)
Financing activities	281,842	262,321	17,303	80,749	8,610
Production:					
Oil (Bbls)	6,871	6,679	6,601	6,037	4,935
Natural gas (Mcf)	21,059	14,089	9,051	8,175	8,078
Combined (BOE)	10,381	9,027	8,110	7,399	6,281
Average Sales Price:					
Oil ($/Bbl)	$ 44.82	$ 33.04	$ 26.72	$ 22.34	$ 21.43
Natural gas ($/Mcf)	7.09	5.53	4.83	3.16	3.73
Combined ($/BOE)	44.05	33.07	27.14	21.72	21.64
Cost per BOE:					
Lease operations	$ 6.59	$ 5.22	$ 4.67	$ 4.15	$ 4.00
Production, ad valorem, and severance taxes	4.39	3.36	2.71	2.12	2.20
Depletion, depreciation, and amortization	8.25	5.38	4.13	4.67	5.05

Exploration	1.39	0.43			
General and administrative (excluding non-cash stock based compensation)	1.42	1.22	1.07	0.83	0.80
Other operating expense	0.91	0.56	0.43	0.28	0.15
Reserves:					
Oil (Bbls)	148,387	134,048	117,732	111,674	91,369
Natural gas (Mcf)	283,865	234,030	138,950	99,818	75,687
Combined (BOE)	195,698	173,053	140,890	128,310	103,983

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	As of December 31,				
	2005	2004	2003	2002	2001
Consolidated Balance Sheet Data:					
Working Capital	$ (56,838)	$ (15,566)	$ (52)	$ 12,489	$ 1,107
Total assets	1,705,705	1,123,400	672,138	549,896	402,000
Long-term debt	673,189	379,000	179,000	166,000	79,107
Stockholders equity	546,781	473,575	358,975	296,266	269,302

(1) For the years ended December 31, 2005, 2004, 2003, 2002, and 2001 we reduced revenue for the payments of the net profits interests by $21.2 million, $12.6 million, $5.8 million, $2.0 million, and $2.8 million, respectively.

(2) Net income for the year ended December 31, 2003 includes $0.9 million income from the cumulative effect of accounting change, which affects its comparability with other periods presented.

(3) Net income for the year ended December 31, 2001 includes $9.6 million of non-cash compensation expense, $4.3 million of bad debt expense, $1.6 million of impairment of oil and natural gas properties, and a $0.9 million charge for the cumulative effect of accounting change, which affects its comparability with other periods presented.

(4) Net income for the year ended December 31, 2005 includes a $12.2 million charge for the early redemption of debt, which affects its comparability with other periods presented.

(5) Net income per common share and the weighted-average number of common shares outstanding have been revised for years prior to 2005 for the effects of the 3-for-2 stock split that occurred on July 12, 2005.

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

The following discussion and analysis of our consolidated financial position and results of operations should be read in conjunction with our financial statements and notes and the supplemental oil and natural gas disclosures included elsewhere in this Report. The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. The words anticipate, estimate, expect, project, intend, plan, believe, should and similar exp identify forward-looking statements. Actual results could differ materially from those stated in the forward-looking statements. We do not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Information Concerning Forward-Looking Statements beginning on page 58 and Item 1A. Risk Factors beginning on page 16.

Introduction

This management s discussion and analysis of financial condition and results of operations is intended to provide investors with information regarding our financial condition and results of operations. The following will be discussed and analyzed:

- Overview of Business
- 2005 Highlights
- Results of Operations
  - Comparison of 2005 to 2004
  - Comparison of 2004 to 2003
- Capital Resources
- Capital Commitments
- Liquidity
- Off-Balance Sheet Arrangements
- Inflation and Changes in Prices
- Critical Accounting Policies and Estimates
- New Accounting Standards
- Information Concerning Forward-Looking Statements

Overview of Business

We engage in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Our business strategies include:

- Maintaining an active drilling and workover program;
- Maximizing existing reserves and programs through high-pressure air injection;
- Utilizing other improved recovery techniques to maximize existing reserves and production;
- Expanding our reserves, production, and drilling inventory through a disciplined acquisition program;

Exploring for reserves; and

Operating in a cost effective, efficient, and safe manner.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Commodity prices continued to strengthen in 2005, with the average NYMEX prices increasing significantly in the past three years. The average oil price per barrel for the NYMEX futures market was $56.56, $41.26, and $31.04 for 2005, 2004, and 2003, respectively. The average natural gas price per MMBTU for the NYMEX futures market was $8.96, $6.11, and $5.50 for 2005, 2004, and 2003, respectively. Commodity prices are influenced by many factors that are outside of our control. We cannot predict future commodity benchmark or wellhead prices. For this reason, we attempt to mitigate the effect of commodity price risk by hedging a portion of our future production.

The significant increase in oil and natural gas prices over the past three years has continued to bid up the price of reserves to historically high levels. We closed two significant acquisitions during 2005. The purchase of Crusader Energy Corporation in October 2005 added substantial proved reserves to our Mid-Continent properties. The November 2005 acquisition of producing properties from Kerr-McGee Corporation also added substantial proved reserves to the Mid-Continent region and the Permian Basin in west Texas. Due to the rising cost of acquisitions, we are continuing to make significant investments within our core areas to develop proved undeveloped reserves and increase production from proved developed reserves through various secondary and tertiary recovery techniques, including our high-pressure air injection program in the CCA. We will, however, continue to evaluate acquisition opportunities as they arise and to the extent we believe we can realize a good rate of return to our shareholders.

We continue to believe that a portfolio of long-lived quality assets will position us for future success, and that reserve replacement is a key statistical measure of our success in growing our asset base. During 2005, we replaced 318% of our 2005 production. Our development program replaced 176% of production and acquisitions replaced 142% of production. See Business and Properties General Oil and Natural Gas Production and Reserves on page 3 for the calculation of our reserve replacement ratios.

Also in 2005, we continued to see positive results from our Phase I high-pressure air injection project at the Pennel unit and the Phase II implementation was completed in 2005. Pennel is the largest unit of the CCA units. In the Little Beaver unit at the southern end of the CCA, we continue to see positive production response in line with expectations with a 800 barrel per day increase over the forecast production decline prior to the initiation of the project. Our independent reserve engineers, Miller and Lents, Ltd. estimated that we added 3.2 million, 9.1 million and 12.5 million barrels, respectively, of proved undeveloped oil reserves associated with our high pressure air injection program at the end of 2005, 2004, and 2003. Over the long term, we believe that high-pressure air injection technology can be applied throughout the Cedar Creek Anticline.

2005 Highlights

Our financial and operating results for the year ended December 31, 2005 include the following:

Oil and natural gas reserves increased 13% to 195.7 MMBOE. During 2005, we added 33.0 MMBOE, replacing 318% of the 10.4 MMBOE produced in 2005. See Business and Properties General Oil and Natural Gas Production and Reserves on page 3 for the calculation of our reserve replacement ratio. Oil reserves accounted for 76% of total proved reserves, and 71% of proved reserves are developed. The estimated pretax present value of our reserves increased by 65% to $2.7 billion (using a 10% discount rate and constant year end prices of $61.04 for oil and $9.44 for natural gas). The Standardized Measure at December 31, 2005 is $1.9 billion. Standardized Measure differs from PV-10 by $760.5 million, because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

During 2005, we had oil and natural gas revenues of $457.3 million. This represents a 53% increase over the $298.5 million of oil and natural gas revenues reported in 2004.

We reported net income of $103.4 million, or $2.09 per diluted share, in 2005. This represents an increase of $21.3 million, or $0.37 per diluted share, over net income reported in 2004. Net income for 2005 was reduced due to a one-time $19.5 million loss on early redemption of debt related to

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redemption premiums and the expensing of unamortized debt issuance costs related to our 8 3/8% senior subordinated notes.

Our realized average oil price for 2005, including the effects of hedging, increased $11.78 per Bbl to $44.82 per Bbl as compared to the 2004 average price of $33.04 per Bbl. Our realized average natural gas price for 2005, including the effects of hedging, increased $1.56 per Mcf to $7.09 per Mcf as compared to the 2004 average price of $5.53 per Mcf.

Production volumes for 2005 increased 15% to 10,381 MBOE (28,442 BOE per day), compared with 2004 production volumes of 9,027 MBOE (24,665 BOE per day). The rise in production volumes was attributable to the continued success of our drilling program, uplift from our HPAI tertiary recovery project in the CCA, and acquisitions completed in 2004 and 2005. Oil represented 66% and 74% of our total production in 2005 and 2004, respectively.

On July 13, 2005, we issued $300.0 million of 6% senior subordinated notes due 2015. We received net proceeds of approximately $294.5 million from the issuance and used approximately $165.9 million of the net proceeds to redeem all of the outstanding principal and related accrued interest of our 8 3/8% senior subordinated notes. The remaining proceeds were used to reduce our indebtedness under our revolving credit facility.

On November 23, 2005, we issued $150.0 million of 7 1/4% senior subordinated notes due 2017. We received net proceeds of approximately $148.5 million and used substantially all of the proceeds to reduce our indebtedness under our revolving credit facility.

We invested $571.3 million in oil and natural gas activities during 2005 (excluding development-related asset retirement obligations). We invested $325.6 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 327 gross (210.6 net) wells, and $245.7 million in acquiring proved properties and undeveloped leases during 2005 (excluding asset retirement obligations). In October 2005, we completed the acquisition of Crusader Energy Corporation, a privately held, independent oil and natural gas company for a purchase price of approximately $109.7 million. In November 2005, we acquired oil and natural gas properties from Kerr-McGee Corporation for approximately $101.4 million. In September 2005, we acquired oil and natural gas properties in the Williston Basin for approximately $28.6 million.

During 2005, we improved our financial flexibility and liquidity by extending the maturity of our revolving credit facility to December 29, 2010 and increasing our borrowing base to $550.0 million. At December 31, 2005, we had $80.0 million outstanding under the revolving credit facility, $50.0 million in outstanding letters of credit, and available borrowing capacity of $420.0 million.

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Results of Operations

Comparison of 2005 to 2004

Below is a comparison of our results of operations for the year ended December 31, 2005 with the year ended December 31, 2004.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2005 and 2004, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit and per day amounts):

	Year Ended December 31,		Increase/	
	2005	2004	(Decrease)	
Revenues:				
Oil wellhead	$ 350,837	$ 255,394	*$ 95,443*	
Oil hedges	(42,878)	(34,745)	*(8,133)*	
Total Oil Revenues	$ 307,959	$ 220,649	*$ 87,310*	*40%*
Natural gas wellhead	$ 165,794	$ 81,112	*$ 84,682*	
Natural gas hedges	(16,429)	(3,228)	*(13,201)*	
Total Natural Gas Revenues	$ 149,365	$ 77,884	*$ 71,481*	*92%*
Combined wellhead	$ 516,631	$ 336,506	*$ 180,125*	
Combined hedges	(59,307)	(37,973)	*(21,334)*	
Total Combined Revenues	$ 457,324	$ 298,533	*$ 158,791*	*53%*
Revenues ($/Unit):				
Oil wellhead	$ 51.06	$ 38.24	*$ 12.82*	
Oil hedges	(6.24)	(5.20)	*(1.04)*	
Total Oil Revenues	$ 44.82	$ 33.04	*$ 11.78*	*36%*
Natural gas wellhead	$ 7.87	$ 5.76	*$ 2.11*	
Natural gas hedges	(0.78)	(0.23)	*(0.55)*	
Total Natural Gas Revenues	$ 7.09	$ 5.53	*$ 1.56*	*28%*
Combined wellhead	$ 49.76	$ 37.28	*$ 12.48*	
Combined hedges	(5.71)	(4.21)	*(1.50)*	
Total Combined Revenues	$ 44.05	$ 33.07	*$ 10.98*	*33%*
Total production volumes:				
Oil (Bbls)	6,871	6,679	*192*	*3%*
Natural gas (Mcf)	21,059	14,089	*6,970*	*50%*
Combined (BOE)	10,381	9,027	*1,354*	*15%*

Daily production volumes:				
Oil (Bbls/day)	18,826	18,249	*577*	*3%*
Natural gas (Mcf/day)	57,696	38,493	*19,203*	*50%*
Combined (BOE/day)	28,442	24,665	*3,777*	*15%*
Average NYMEX Prices:				
Oil (per Bbl)	$ 56.56	$ 41.26	*$ 15.30*	*37%*
Natural gas (per Mcf)	8.96	6.11	*2.85*	*47%*

Oil revenues increased $87.3 million from $220.6 million in 2004 to $308.0 million in 2005. The increase is due primarily to higher realized average oil prices which contributed approximately $80.0 million in additional revenues and an increase in oil production volumes of 192 MBbl which contributed approximately $7.3 million in additional revenues. The $80.0 million increase in revenues from higher realized average oil prices consists of an $88.1 million increase resulting from higher average wellhead oil prices, offset by increased hedging payments of $8.1 million, or $1.04 per Bbl. Our average wellhead oil price increased $12.82 per Bbl in 2005 over 2004 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $41.26 in 2004 to $56.56 in 2005.

Our oil wellhead revenue was reduced by $20.6 million and $12.3 million in 2005 and 2004, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $71.5 million from $77.9 million in 2004 to $149.4 million in 2005. The increase is due primarily to increased natural gas production volumes of 6,970 MMcf which contributed approximately $40.1 million in additional revenues and higher realized average natural gas prices which contributed approximately $31.4 million in additional revenues. The $31.4 million increase in revenues from higher realized average natural gas prices consists of a $44.6 million increase resulting from higher average wellhead natural gas prices, offset by increased hedging payments of $13.2 million, or $0.55 per Mcf. Our average wellhead natural gas price increased $2.11 per Mcf in 2005 over 2004 due to an increase in the overall market price of natural gas as reflected in the increase in the average NYMEX price from $6.11 in 2004 to $8.96 in 2005.

The prices we receive for our oil and natural gas production are largely based on current market prices, which are beyond our control. For comparability and accountability, we take a constant approach to budgeting commodity prices. We presently analyze our inventory of capital projects based on NYMEX prices of $55.00 per Bbl and $7.00 per Mcf. We do not assume any escalation of commodity prices when preparing our capital budget. If NYMEX prices trend downward below our base deck, we may reevaluate our capital projects. If commodity prices are significantly lower than our forecasted prices of $55.00 for oil and $7.00 for natural gas, it could have a material effect on our projected 2006 results. In this case, we would have to borrow additional money under our existing revolving credit facility, attempt to access the capital markets, or curtail the capital program. If drilling is curtailed or ended, future cash flows could be materially negatively impacted.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the years ended December 31, 2005 and 2004. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2005	**2004**
Oil wellhead ($/Bbl)	$ 51.06	$ 38.24
Average NYMEX ($/Bbl)	$ 56.56	$ 41.26
Differential to NYMEX	$ (5.50)	$ (3.02)
Oil wellhead to NYMEX percentage	90%	93%
Natural gas wellhead ($/Mcf)	$ 7.87	$ 5.76
Average NYMEX ($/Mcf)	$ 8.96	$ 6.11
Differential to NYMEX	$ (1.09)	$ (0.35)
Natural gas wellhead to NYMEX percentage	88%	94%

In the fourth quarter of 2005, the oil wellhead to NYMEX price percentage decreased to as low as 88%. We expect this oil wellhead to NYMEX price percentage to decrease further in the first half of 2006 to approximately 75% to

80%. We attribute this widening to market conditions in the Rocky Mountain area, which is expected to adversely affect the wellhead price we receive in the CCA. In recent years,

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production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited takeaway capacity from the Rocky Mountain area, have gradually widened the differential between our wellhead price and the benchmark NYMEX price at Cushing, Oklahoma. A particularly active turnaround season in the first quarter of 2006 on the part of the Rocky Mountain area refiners will lead to a further widening of the differential. We cannot accurately predict crude oil differentials for subsequent quarters.

In the fourth quarter of 2005, the natural gas wellhead to NYMEX price percentage decreased to as low as 75% due to pipeline capacity constraints. We expect that this natural gas wellhead to NYMEX price percentage will remain approximately constant in the first half of 2006.

Expenses. The following table summarizes our expenses for the years ended December 31, 2005 and 2004:

	Year Ended December 31,			
	2005	2004	*Increase/* (Decrease)	
Expenses (in thousands):				
Production				
Lease operations	$ 68,395	$ 47,142	*$ 21,253*	
Production, ad valorem, and severance taxes	45,601	30,313	*15,288*	
Total production expenses	113,996	77,455	*36,541*	*47%*
Other				
Depletion, depreciation, and amortization	85,627	48,522	*37,105*	
Exploration	14,402	3,907	*10,495*	
General and administrative (excluding non-cash stock based compensation)	14,696	10,982	*3,714*	
Non-cash stock based compensation	3,962	1,770	*2,192*	
Derivative fair value loss	5,290	5,011	*279*	
Loss on early redemption of debt	19,477		*19,477*	
Other operating	9,485	5,028	*4,457*	
Total operating	266,935	152,675	*114,260*	*75%*
Interest	34,055	23,459	*10,596*	
Current and deferred income tax provision	53,948	40,492	*13,456*	
Total expenses	$ 354,938	$ 216,626	*$ 138,312*	*64%*

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	Year Ended December 31, 2005	2004	*Increase/* (Decrease)	
Expenses (per BOE):				
Production				
Lease operations	$ 6.59	$ 5.22	*$ 1.37*	
Production, ad valorem, and severance taxes	4.39	3.36	*1.03*	
Total production expenses	10.98	8.58	*2.40*	*28%*
Other				
Depletion, depreciation, and amortization	8.25	5.38	*2.87*	
Exploration	1.39	0.43	*0.96*	
General and administrative (excluding non-cash stock based compensation)	1.42	1.22	*0.20*	
Non-cash stock based compensation	0.38	0.20	*0.18*	
Derivative fair value loss	0.51	0.56	*(0.05)*	
Loss on early redemption of debt	1.88		*1.88*	
Other operating	0.91	0.56	*0.35*	
Total operating	25.72	16.93	*8.79*	*52%*
Interest	3.28	2.60	*0.68*	
Current and deferred income tax provision	5.20	4.49	*0.71*	
Total expenses	$ 34.20	$ 24.02	*$ 10.18*	*42%*

Production expenses (Lease operations and production, ad valorem, and severance taxes). Total production expenses increased $36.5 million from $77.5 million in 2004 to $114.0 million in 2005. This increase resulted from an increase in total production volumes, as well as a $2.40 increase in production expenses per BOE. The 28% increase in total production expenses per BOE compares to a 33% increase in revenues per BOE due to a higher production margin (defined as revenues less production expenses) in 2005 as compared to 2004.

The production expense attributable to lease operations for 2005 increased as compared to 2004 by $21.3 million due to an increase in production volumes and an increase in the average per BOE rate. The increase in production volumes are the result of our 2005 drilling program; the 2005 and 2004 acquisitions, and our secondary and tertiary recovery programs, including the waterflood enhancement program and the high-pressure air injection program. These increased volumes resulted in approximately $7.1 million of additional lease operations expense. The increase in our average expense per BOE was attributable to increases in prices paid to oilfield service companies and suppliers due to a current higher price environment, increased operational activity to maximize production, and the operation of higher operating cost wells, which have become more attractive due to increases in oil and natural gas prices. This increased average per BOE rate resulted in approximately $14.2 million of additional lease operations expense for price escalation for services.

For 2006, we anticipate an increase in lease operations expense on both an aggregate and a per BOE basis. We anticipate the overall increase due to a full year of production at our properties acquired in 2005; further implementation of the high-pressure air injection program and a full year of production expenses related to the Little Beaver HPAI project; and the adoption of SFAS 123R. See Non-cash stock based compensation expense below. In the third quarter of 2005, we began expensing HPAI production costs attributable to Little Beaver Phase I that previously were being capitalized during the pressurization phase.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) for 2005 increased as compared to 2004 by $15.3 million due to an increase in production volumes and an increase in the average wellhead price we received for oil and natural gas production. The increase in production volumes over 2004 resulted in approximately $4.5 million of additional production taxes. The average wellhead price we received for oil and natural gas revenues increased $12.48 per BOE, resulting in additional production taxes of approximately $10.8 million in 2005. As a percentage of oil and natural gas revenues (excluding the effect of hedges), production taxes for 2005 decreased slightly from 9.0% for 2004 to 8.8% for 2005. The effect of hedges is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production taxes paid to taxing authorities.

For 2006, total production taxes will depend in a large part on prevailing oil and natural gas prices. However, the production tax rate should remain relatively constant at approximately 9.0% of wellhead revenues before hedging.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $37.1 million from $48.5 million in 2004 to $85.6 million in 2005 due to a higher per BOE rate and increased production volumes. The per BOE rate increased $2.87 from 2004 due to the development of proved undeveloped reserves from the 2004 acquisitions, which do not increase total proved reserves, and higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas. These factors resulted in additional DD&A expense of $29.8 million. The increase in production volumes of 1,352 MBOE over 2004 resulted in $7.3 million of additional DD&A expense.

We anticipate that total DD&A expense in 2006 will increase due to increased production and our planned 2006 capital expenditures of $320.0 million. We expect the invested capital to add barrels through the drill bit in 2006 at a cost higher than our historical DD&A rate. Assuming capital expenditures do not differ significantly from our budgeted amount, we expect our DD&A rate for 2006 to be higher per BOE. The DD&A rate could vary significantly based on actual capital expenditures, production rates, net profits interests, and any acquisitions that close in 2006. Additionally, changes in the market price for oil and natural gas could affect the level of our reserves.

Exploration expense. Exploration expense increased $10.5 million in 2005 as compared to 2004. During 2005, we expensed 47 exploratory dry holes totaling $8.6 million. Of the 47 exploratory dry holes expensed, 45 were drilled in the shallow gas area of Montana, 1 was drilled in the Permian Basin, and 1 was drilled in the CCA. In 2004, we expensed 4 exploratory dry holes at a cost of $2.0 million. In 2004, three of the exploratory dry holes were drilled in our Montana shallow gas area and one was drilled in the Barnett Shale in our Mid-Continent area. The following table details our exploration-related expenses (in thousands):

	Year Ended December 31, 2005	**Year Ended December 31, 2004**	***Increase/* (Decrease)**
Exploration expenses:			
Dry hole	$ 8,632	$ 2,050	*$ 6,582*
Geological and geophysical	1,247	425	*822*
Seismic	1,849	553	*1,296*
Delay rentals	635	204	*431*
Impairment of unproved acreage	2,039	675	*1,364*
Total	$ 14,402	$ 3,907	*$ 10,495*

For 2006, we expect to continue to incur exploration expense as we continue our current exploration projects in the Mid-Continent and Montana shallow gas area. This amount could vary considerably, however, based on the success of these projects. Additionally, the adoption of SFAS 123R will increase exploration expense in 2006 for non-cash stock compensation both in total and per BOE. See Non-cash stock based compensation expense below.

With the current commodity price environment, we believe exploration programs can provide a rate of return comparable or superior to property acquisitions in certain areas. We seek to acquire undeveloped

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acreage and/or enter into drilling arrangements to explore in areas that complement our portfolio of properties. In keeping with our exploitation focus, the exploration projects are expected to set up multi-well exploitation projects if successful.

General and administrative (G&A) expense. G&A expense (excluding non-cash stock based compensation) increased $3.7 million from $11.0 million in 2004 to $14.7 million in 2005. The overall increase, as well as the $0.20 increase in the per BOE rate, is a result of increased staffing to manage our larger asset base, higher activity levels, and increased personnel costs due to intense competition for human resources within the industry.

We have forecast general and administrative expenses in 2006 to increase approximately 30% to 35% as compared to 2005. The increase from 2005 is expected to result from increased staffing to manage our larger asset base and continuing increases in the costs to hire and retain experienced industry personnel, as well as the effect of adoption of SFAS 123R, which will increase general and administrative expense in 2006 both in total and per BOE. See Non-cash stock based compensation expense below.

Non-cash stock based compensation expense. Non-cash stock based compensation expense for 2005 increased $2.2 million from $1.8 million in 2004 to $4.0 million in 2005. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under our 2000 Incentive Stock Plan. Amortization of deferred compensation increased from 2004 primarily due to amortization recorded during 2005 related to 286,044 shares of restricted stock granted in 2005. In addition, certain restricted stock grants contain performance vesting provisions which require us to recognize periodic expense based on our current stock price, rather than the stock price at the day of grant. As a result, our higher stock price has also resulted in increased amortization expense.

During the years ended December 31, 2005, 2004, and 2003, we issued 130,854, 102,106, and 68,191 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. The following table illustrates by year of grant the vesting of these shares which remain outstanding at December 31, 2005:

	Year of Vesting					
Year of Grant	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
2002	52,694	52,693				105,387
2003	19,569	19,522	19,522			58,613
2004	28,462	33,362	4,899	4,898		71,621
2005	5,511	5,511	42,367	36,793	36,793	126,975
Total	106,236	111,088	66,788	41,691	36,793	362,596

During the years ended December 31, 2005, 2004, and 2003, we issued 155,190, 86,537, and zero shares of restricted stock to employees that not only depend on the passage of time and continued employment, but also on certain performance measures for their vesting. The following table illustrates by year of grant the vesting of these performance based shares which remain outstanding at December 31, 2005:

	Year of Vesting					
Year of Grant	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
2004		25,832	25,828	25,828		77,488
2005			47,730	47,730	47,730	143,190
Total		25,832	73,558	73,558	47,730	220,678

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Total deferred compensation of $9.0 million was outstanding and included in Deferred Compensation in the accompanying Consolidated Balance Sheet as of December 31, 2005. Estimated amortization of deferred compensation is shown in the table below (in thousands) as of December 31, 2005:

Year Ended December 31,	Estimated Amortization Expense
2006	$ 3,835
2007	2,918
2008	1,567
2009	617
2010	70
Total	$ 9,007

The estimated non-cash stock based compensation expense shown above is in part dependent on fluctuations in our stock price because, as noted above, certain awards are accounted for as variable awards as they are based on achievement of certain performance measures. Subsequent to December 31, 2005, we issued 389,922 shares of restricted stock to our employees as part of our annual incentive program.

Effective January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standards No. 123R, Share-Based Payment , which requires that companies recognize in their financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. As a result, in 2006 we will recognize expense associated with stock options granted under our 2000 Incentive Stock Plan, which previously was only presented in pro forma disclosures. Total non-cash stock based compensation expense expected to be recorded in 2006, consisting of expense associated with both restricted stock and stock options, is approximately $10.0 million. This amount will not be reported separately on the Consolidated Statement of Operations but will be allocated to lease operations, exploration, and general and administrative expense.

Derivative fair value loss. During 2005, we recorded a $5.3 million derivative fair value loss as compared to a $5.0 million loss recorded in 2004. This derivative fair value loss represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed-to-floating interest rate swaps, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed-to-floating interest rate swap. The components of the derivative fair value (gain) loss reported in 2005 and 2004 are as follows (in thousands):

	Year Ended December 31, 2005	Year Ended December 31, 2004	*Increase/* (Decrease)
Designated cash flow hedges:			
Ineffectiveness Commodity contracts	$ 8,371	$ 5,018	*$ 3,353*
Undesignated derivative contracts:			
Mark-to-market (gain) loss Interest rate swap	150	272	*(122)*
Mark-to-market (gain) loss Commodity contracts	(3,231)	(279)	*(2,952)*
Total derivative fair value (gain) loss	$ 5,290	$ 5,011	*$ 279*

Ineffectiveness loss related to our derivative commodity contracts designated as hedges increased $3.4 million due primarily to an increase in oil wellhead differentials on our production in the CCA. The interest rate swap loss decreased from 2004 due to the expiration of our fixed-to-floating interest rate swap in June 2005. The ineffectiveness loss is offset by a $3.2 million gain related to undesignated commodity contracts which increased due to changes in the fair value of certain natural gas basis swaps.

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As we previously discussed, our oil wellhead differentials are expected to increase at least through the first half of 2006. For this reason, we expect derivative fair value loss to increase in 2006 from 2005 due to additional ineffectiveness on our designated cash flow hedges. Significant and sustained increases in our oil wellhead differential could preclude the application of hedge accounting to many of our derivative contracts, and should this occur, future mark-to-market gains or losses would be recognized as Derivative fair value (gain) loss in the Consolidated Statements of Operations immediately. This could result in material fluctuations in net income and stockholders equity from period to period.

Loss on early redemption of debt. In 2005, we recorded a one-time $19.5 million loss on early redemption of debt related to the redemption premium and the write-off of unamortized debt issuance costs of our 8^{3}/8% senior subordinated notes. We redeemed the 8^{3}/8% notes with proceeds received from the issuance of our $300.0 million 6% senior subordinated notes in July 2005.

Other operating expense. Other operating expense increased $4.5 million from $5.0 million in 2004 to $9.5 million in 2005. This increase is mainly due to an increase in third party natural gas transportation costs attributable to higher production volumes for 2005 as compared to 2004.

For 2006, we anticipate other operating expense to increase over 2005, which reflects the increased transportation costs associated with higher expected production volumes.

Interest expense. Interest expense increased $10.6 million in 2005 as compared to 2004. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150.0 million of 7^{1}/4% senior subordinated notes in November 2005, $300.0 million of 6% senior subordinated notes in July 2005, and $150.0 million of 6^{1}/4% senior subordinated notes in April 2004. We also redeemed $150.0 million of 8^{3}/8% senior subordinated notes in August 2005. The weighted average interest rate, net of hedges, for 2005 was 6.8% as compared to 7.7% for 2004. This lower weighted average interest rate is the result of the debt issuances which have rates lower than our historical average rate.

The following table illustrates the components of interest expense for 2005 and 2004 (in thousands):

	Year Ended December 31,		
	2005	**2004**	***Increase/* (Decrease)**
8^{3}/8 senior subordinated notes due 2012	$ 7,852	$ 12,563	*$ (4,711)*
6^{1}/4% senior subordinated notes due 2014	9,375	7,005	*2,370*
6% senior subordinated notes due 2015	8,437		*8,437*
7^{1}/4% senior subordinated notes due 2017	1,145		*1,145*
Revolving credit facility	4,554	1,565	*2,989*
Letters of credit	615	170	*445*
Interest rate hedges	42	546	*(504)*
Debt issuance costs amortization	979	969	*10*
Banking fees and other	847	641	*206*
Debt discount amortization	209		*209*
Total	$ 34,055	$ 23,459	*$ 10,596*

We have forecast interest expense to increase in 2006 as compared to 2005. The increase from 2005 is primarily due to higher levels of debt resulting from the senior subordinated note issuances in 2005. This forecast could vary considerably as future acquisitions may be funded with our revolving credit facility or new debt issuances.

Income taxes. Income tax expense for 2005 increased $13.5 million from 2004. This increase is due primarily to an increase of $34.7 million in income before income taxes. Our effective tax rate increased slightly in 2005 to 34.3% from 33.0% in 2004.

As of December 31, 2005, we had generated approximately $13.2 million of Section 43 credits related to our HPAI program. If unused, $2.0 million of the Section 43 credits will expire in 2023, $6.1 million in 2024, and $5.1 million in 2025.

To the extent our drilling and development activities continue to be greater than our cash flows for operating activities, we expect to pay immaterial amounts of current income taxes in 2006 with the largest percentage of our tax expense being deferred.

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Comparison of 2004 to 2003

Below is a comparison of our results of operations for the year ended December 31, 2004 with the year ended December 31, 2003.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2004 and 2003, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit and per day amounts):

	Year Ended December 31, 2004	Year Ended December 31, 2003	*Increase/* (Decrease)	
Revenues:				
Oil wellhead	$ 255,394	$ 190,203	*$ 65,191*	
Oil hedges	(34,745)	(13,852)	*(20,893)*	
Total Oil Revenues	$ 220,649	$ 176,351	*$ 44,298*	*25%*
Natural gas wellhead	$ 81,112	$ 45,218	*$ 35,894*	
Natural gas hedges	(3,228)	(1,473)	*(1,755)*	
Total Natural Gas Revenues	$ 77,884	$ 43,745	*$ 34,139*	*78%*
Combined wellhead	$ 336,506	$ 235,421	*$ 101,085*	
Combined hedges	(37,973)	(15,325)	*(22,648)*	
Total Combined Revenues	$ 298,533	$ 220,096	*$ 78,437*	*36%*
Revenues ($/Unit):				
Oil wellhead	$ 38.24	$ 28.82	*$ 9.42*	
Oil hedges	(5.20)	(2.10)	*(3.10)*	
Total Oil Revenues	$ 33.04	$ 26.72	*$ 6.32*	*24%*
Natural gas wellhead	$ 5.76	$ 5.00	*$ 0.76*	
Natural gas hedges	(0.23)	(0.17)	*(0.06)*	
Total Natural Gas Revenues	$ 5.53	$ 4.83	*$ 0.70*	*14%*
Combined wellhead	$ 37.28	$ 29.03	*$ 8.25*	
Combined hedges	(4.21)	(1.89)	*(2.32)*	
Total Combined Revenues	$ 33.07	$ 27.14	*$ 5.93*	*22%*
Total production volumes:				
Oil (Bbls)	6,679	6,601	*78*	*1%*
Natural gas (Mcf)	14,089	9,051	*5,038*	*56%*
Combined (BOE)	9,027	8,110	*917*	*11%*
Daily production volumes:				

Oil (Bbls/day)	18,249	18,085	*164*	*1%*
Natural gas (Mcf/day)	38,493	24,798	*13,695*	*55%*
Combined (BOE/day)	24,665	22,218	*2,447*	*11%*
Average NYMEX Prices:				
Oil (per Bbl)	$ 41.26	$ 31.04	*$ 10.22*	*33%*
Natural gas (per Mcf)	6.11	5.50	*0.61*	*11%*

Oil revenues increased $44.3 million from $176.4 million in 2003 to $220.6 million in 2004. The increase is due primarily to higher average realized oil prices which contributed approximately

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$42.0 million in additional revenues and an increase in oil production volumes of 78 MBbls which contributed approximately $2.3 million. The $42.0 million increase in revenues from higher average realized oil prices consists of a $62.9 million increase resulting from higher average wellhead prices, offset by increased hedging payments of $20.9 million, or $3.10 per Bbl. Our average wellhead oil price increased $9.42 per Bbl in 2004 over 2003 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $31.04 in 2003 to $41.26 in 2004.

Our oil wellhead revenue was reduced by $12.3 million and $5.6 million in 2004 and 2003, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $34.1 million from $43.7 million in 2003 to $77.9 million in 2004. The increase is, due primarily to increased natural gas production of 5,038 MMcf which contributed approximately $25.2 million in additional revenues and an increase in the average realized natural gas price which contributed approximately $8.9 million in additional revenues. The $8.9 million increase in revenues from higher average realized natural gas prices consists of a $10.7 million increase resulting from higher average wellhead natural gas prices, offset by increased hedging payments of $1.8 million, or $0.06 per Mcf. Our average wellhead natural gas price increased $0.76 per Mcf in 2004 over 2003 due to an increase in the overall market price of natural gas as reflected in the increase in the average NYMEX price from $5.50 in 2003 to $6.11 in 2004.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the years ended December 31, 2004 and 2003. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2004	**2003**
Oil wellhead ($/Bbl)	$ 38.24	$ 28.82
Average NYMEX ($/Bbl)	$ 41.26	$ 31.04
Differential to NYMEX	$ (3.02)	$ (2.22)
Oil wellhead to NYMEX percentage	93%	93%
Natural gas well ($/Mcf)	$ 5.76	$ 5.00
Average NYMEX ($/Mcf)	$ 6.11	$ 5.50
Differential to NYMEX	$ (0.35)	$ (0.50)
Natural gas wellhead to NYMEX percentage	94%	91%

Our differentials to the average NYMEX prices increased on a per unit basis while our wellhead prices as a percentage of the average NYMEX prices remained fairly consistent from 2003 to 2004.

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Expenses. The following table summarizes our expenses for the years ended December 31, 2004 and 2003:

	Year Ended December 31, 2004	Year Ended December 31, 2003	*Increase/ (Decrease)*	
Expenses (in thousands):				
Production				
Lease operations	$ 47,142	$ 37,846	*$ 9,296*	
Production, ad valorem, and severance taxes	30,313	22,013	*8,300*	
Total production expenses	77,455	59,859	*17,596*	*29%*
Other				
Depletion, depreciation, and amortization	48,522	33,530	*14,992*	
Exploration	3,907		*3,907*	
General and administrative (excluding non-cash stock based compensation)	10,982	8,680	*2,302*	
Non-cash stock based compensation	1,770	614	*1,156*	
Derivative fair value (gain) loss	5,011	(885)	*5,896*	
Other operating	5,028	3,481	*1,547*	
Total operating	152,675	105,279	*47,396*	*45%*
Interest	23,459	16,151	*7,308*	
Current and deferred income tax provision	40,492	36,102	*4,390*	
Total expenses	$ 216,626	$ 157,532	*$ 59,094*	*38%*
Expenses (per BOE):				
Production				
Lease operations	$ 5.22	$ 4.67	*$ 0.55*	
Production, ad valorem, and severance taxes	3.36	2.71	*0.65*	
Total production expenses	8.58	7.38	*1.20*	*16%*
Other				
Depletion, depreciation, and amortization	5.38	4.13	*1.25*	
Exploration	0.43		*0.43*	
General and administrative (excluding non-cash stock based compensation)	1.22	1.07	*0.15*	
Non-cash stock based compensation	0.20	0.08	*0.12*	
Derivative fair value (gain) loss	0.56	(0.11)	*0.67*	
Other operating	0.56	0.43	*0.13*	
Total operating	16.93	12.98	*3.95*	*30%*
Interest	2.60	1.99	*0.61*	
Current and deferred income tax provision	4.49	4.45	*0.04*	
Total expenses	$ 24.02	$ 19.42	*$ 4.60*	*24%*

Production expenses (Lease operations and production, ad valorem, and severance taxes). Total production expenses increased $17.6 million from $59.9 million in 2003 to $77.5 million in 2004. This increase resulted from an increase in total production volumes, as well as a $1.20 increase in production expenses per BOE. The 16% increase in total production expenses per BOE compares to a 22% increase in revenues per BOE due to a higher production margin (defined as revenues less production expenses) in 2004 as compared to 2003.

The production expense attributable to lease operations for 2004 increased as compared to 2003 by $9.3 million due to an increase in production volumes and an increase in the average per BOE rate. The increase in production volumes are the result of our 2004 drilling program, our HPAI program, and the Elm Grove, Cortez, and Overton acquisitions. These increased production volumes resulted in approximately $4.3 million of additional lease operations expense. The increase in our average expense per BOE was attributable to properties acquired with higher per BOE expenses and an increase in prices paid to oilfield services companies and suppliers. This increased average per BOE rate resulted in approximately $5.0 million of additional lease operations expense.

The production expense attributable to production, ad valorem, and severance taxes for 2004 increased as compared to 2003 by $8.3 million due to an increase in production volumes and an increase in the average wellhead price we received for oil and natural gas revenues. The increase in production volumes over 2003 resulted in approximately $2.5 million of additional production, ad valorem, and severance taxes. The average wellhead price we received for oil and natural gas production increased $8.25 per BOE, resulting in additional production, ad valorem, and severance taxes of approximately $5.8 million in 2004. As a percentage of oil and natural gas revenues (excluding the effect of hedges), production, ad valorem, and severances taxes for 2004 decreased slightly from 9.4% for 2003 to 9.0% for 2004. The effect of hedges is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production, ad valorem, and severance taxes paid to taxing authorities.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $15.0 million from $33.4 million in 2003 to $48.5 million in 2004 due to an increase in the per BOE rate as well as an increase in production volumes. The per BOE rate increased $1.25 from 2003 due to the acquisition of the Overton and Cortez properties, which had higher acquisition costs than our historical average, and higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas. These factors resulted in additional DD&A expense of approximately $11.2 million in 2004. The increase in production volumes of 917 MBOE over 2003 resulted in additional DD&A expense of approximately $3.8 million in 2004.

Exploration expense. Exploration costs totaled $3.9 million in 2004 as we began an exploration program in 2004. In 2004, we drilled 4 exploratory dry holes at a cost of $2.1 million. This compares to 2003 when zero exploratory dry holes were drilled. Three of the exploratory dry holes were drilled in our Montana shallow gas area and one was drilled in the Barnett Shale in our Mid-Continent area. In addition to the increase in dry hole expense, additional exploration-related expenses were incurred in 2004 related to our exploration projects. We incurred abandonment and impairment of undeveloped acreage costs of $0.7 million, delay rental expense of $0.2 million, seismic costs of $0.6 million, and other geological and geophysical expenses of $0.3 million.

General and administrative (G&A) expense. G&A expense increased $2.3 million from $8.7 million in 2003 to $11.0 million in 2004. The increase in G&A expense was a result of increased staffing levels used to manage our growing asset base and outside consulting services used in the evaluation of potential acquisitions and costs associated with compliance with the Sarbanes-Oxley Act of 2002.

Non-cash stock based compensation expense. Non-cash stock based compensation expense increased from $0.6 million in 2003 to $1.8 million in 2004. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under our 2000 Incentive Stock Plan.

During the years ended December 31, 2004, 2003, and 2002, we issued 68,071, 45,461, and 77,901 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. During the years ended December 31, 2004, 2003, and 2002, we also issued 57,693, zero, and 51,427 shares of restricted stock to employees that not only depend on the passage of time and continued employment, but also on certain performance measures for their vesting. Accordingly, the awards with performance vesting measures are accounted for as variable awards.

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Derivative fair value (gain) loss. During 2004, we recorded a $5.0 million derivative fair loss as compared to a $0.9 million gain in 2003. This derivative fair value (gain) loss represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed to floating interest rate swap, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed to floating interest rate swap. The components of the derivative fair value (gain) loss reported in 2004 and 2003 are as follows (in thousands):

	Year Ended December 31, 2004	Year Ended December 31, 2003	*Increase/ (Decrease)*
Designated cash flow hedges:			
Ineffectiveness Commodity contracts	$ 5,018	$ 818	*$ 4,200*
Undesignated derivative contracts:			
Mark-to-market (gain) loss Interest rate swap	272	(2,098)	*2,370*
Mark-to-market (gain) loss Commodity contracts	(279)	395	*(674)*
Total derivative fair value (gain) loss	$ 5,011	$ (885)	*$ 5,896*

Ineffectiveness loss related to our contracts increased $4.2 million due primarily to an increase in oil differentials on our production in the CCA. In conjunction with the issuance of 8$^{3}/8$% notes in June 2002, we entered into an interest rate swap, which swaps fixed rates to floating, with the intent of lowering our effective interest payments. As this transaction did not qualify for hedge accounting, changes in its fair market value, as well as settlements, were not recorded in interest expense, but in Derivative fair value (gain) loss on the Consolidated Statements of Operations.

Other operating expense. Other operating expense increased $1.5 million from $3.5 million in 2003 to $5.0 million in 2004. The increase in other operating expense is primarily attributable to a $1.3 million increase in oil and natural gas transportation expense and a $0.9 million increase in loss on sale of properties, offset by a $0.8 million decrease in severance payments to former employees.

Interest expense. Interest expense for the year ended December 31, 2004 increased $7.3 million over 2003 due primarily to an increase in debt outstanding under our credit facility and the 6$^{1}/4$% notes issued in April 2004, offset slightly by a decrease in our weighted average interest rate from period to period. The weighted average interest rate, net of hedges, for 2004 was 7.7% compared to 9.6% for 2003. This lower weighted average interest rate is the result of the 2004 debt issuance which has a lower rate than our historical average.

The following table illustrates the components of interest expense for 2004 and 2003 (in thousands):

	Year Ended December 31, 2004	Year Ended December 31, 2003	*Increase/ (Decrease)*
8$^{3}/8$% senior subordinated notes due 2012	$ 12,563	$ 12,563	*$*
6$^{1}/4$% senior subordinated notes due 2014	7,005		*7,005*
Revolving credit facility	1,565	453	*1,112*
Interest rate hedges	546	1,910	*(1,364)*
Debt issuance costs amortization	969	714	*255*
Banking fees and other	811	511	*300*

Total	$ 23,459	$ 16,151	*$ 7,308*

Income tax expense. Income tax expense increased $4.4 million from $36.1 million in 2003 to $40.5 million in 2004. This increase is due primarily to the $23.8 million increase in income before income taxes from 2003 to 2004 offset by a decrease in our effective tax rate from 36.5% in 2003 to 33.0% in 2004. The decrease in effective income tax rate resulted from an incremental increase of $4.0 million for Section 43 credits ($6.1 million in Section 43 credits in 2004 as compared to $2.1 million in 2003) and the effect of the change in our state effective tax rate from 3.0% to 2.4% in 2004 due to changes in the asset mix and apportionment factors.

Capital Resources

Our primary capital resources are as follows:

Cash flows from operating activities

Cash flows from financing activities

Current capitalization

Cash flows from operating activities. Cash provided by operating activities increased $120.5 million from $171.8 million in 2004 to $292.3 million in 2005. This increase resulted mainly from an increase in revenues which outpaced the increase in total operating expenses. Revenues increased in 2005 as both production volumes and commodity prices were higher than in 2004. Our production volumes increased 1,354 MBOE from 9,027 MBOE in 2004 to 10,381 MBOE in 2005. Our average realized oil price increased $11.78 per Bbl from $33.04 per Bbl in 2004 to $44.82 in 2005. Our average realized natural gas price increased $1.56 per Mcf from $5.53 in 2004 to $7.09 per Mcf in 2005. Total operating expenses increased $114.3 million from $152.7 million in 2004 to $266.9 million in 2005.

For 2004 as compared to 2003, cash provided by operating activities increased by $48.0 million, primarily because of an increase in revenues which outpaced the increase in total operating expenses. Revenues increased in 2004 as both production volumes and commodity prices were higher than in 2003. Our production volume increased 917 MBOE from 8,110 MBOE in 2003 to 9,027 MBOE in 2004. Our average realized oil price increased $6.32 per Bbl from $26.72 per Bbl in 2003 to $33.04 per Bbl in 2004. Our average realized natural gas price increased $0.70 per Mcf from $4.83 per Mcf in 2003 to $5.53 per Mcf in 2004. Total operating expenses in 2004 increased $47.4 million from $105.3 million in 2003 to $152.7 million in 2004.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt. During 2005, we received net cash of $281.8 million from financing activities.

In July 2005, we issued $300.0 million of 6% senior subordinated notes. We received net proceeds of approximately $294.5 million from the issuance and used approximately $165.9 million of the net proceeds to redeem all the outstanding principal of our 8^{3}/8% senior subordinated notes and to pay related early redemption premiums. The remaining proceeds of the 6% senior subordinated notes were used to reduce indebtedness under our revolving credit facility. Prior to the issuance of these notes, the outstanding balance on our revolving credit facility was $140.0 million.

In November 2005, we issued $150.0 million of 7^{1}/4% senior subordinated notes. We received net proceeds of approximately $148.5 million from the issuance and used substantially all of the proceeds to reduce indebtedness under our revolving credit facility. Prior to the issuance of these notes, the outstanding balance on our revolving credit facility was $149.0 million.

We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments. Historically, we have converted large balances on our revolving credit facility to senior subordinated notes to extend the maturity date of the debt and fix the interest rate. Our total borrowings less repayments on our revolving credit facility, as described above, resulted in a net increase in the outstanding balance of our revolving credit facility of $1.0 million from $79.0 million at December 31, 2004 to $80.0 million at December 31, 2005.

During 2004, we received net cash of $262.3 million from financing activities. On April 2, 2004, we issued $150.0 million of 6^{1}/4% senior subordinated notes and received net proceeds of approximately $146.4 million. On June 10, 2004, we issued and sold 2.0 million shares of our common stock to the public at a price of $26.95 per share. The net proceeds of the common stock offering, after underwriting discounts and commissions and other expenses, were approximately $52.9 million. We used the net proceeds of the debt issuance and common stock offering to fund the 2004 acquisition of Cortez, repay indebtedness under our revolving credit facility, and for general corporate purposes.

Total borrowings less repayments on our revolving credit facility in 2004 resulted in a net increase in the outstanding balance of our revolving credit facility of $50.0 million from $29.0 million at December 31, 2003 to $79.0 million at December 31, 2004.

During 2003 proceeds from financing activities were $17.3 million. Net proceeds of approximately $13.0 million from our revolving credit facility were used to fund various 2003 acquisitions and for general corporate purposes. In the fourth quarter of 2003, we issued a total of 9.06 million shares of our common stock to the public at a price of $20.25 per share. The net proceeds of the offering of approximately $175.1 million were used to repurchase 9.06 million shares from former investors in our company at a total cost of $175.6 million.

Current capitalization. At December 31, 2005, we had total assets of $1.7 billion. Total capitalization as of December 31, 2005 was $1.2 billion, of which 45% was represented by stockholders equity and 55% by long-term debt. At December 31, 2004, we had total assets of $1.1 billion. Total capitalization as of December 31, 2004 was $852.6 million, of which 56% was represented by stockholders equity and 44% by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt is used to finance potential future acquisitions.

Capital Commitments

Our primary needs for cash are as follows:

- Development, exploitation, and exploration of our existing oil and natural gas properties
- Acquisitions of oil and natural gas properties and leasehold acreage costs
- Other general property and equipment
- Funding of necessary working capital
- Payment of contractual obligations

For 2006, our Board of Directors has approved the following $320.0 million capital budget for oil and natural gas related activities, excluding asset retirement obligations and potential acquisitions (in thousands):

	2006
Budgeted Capital Expenditures:	
Development, exploitation, and exploration	$ 270,000
HPAI	32,000
Leasehold acreage acquisition and other	18,000
Total	$ 320,000

We currently analyze our inventory of capital projects based on $55.00 per Bbl of oil and $7.00 per Mcf of natural gas NYMEX prices. We do not assume any escalation of commodity prices when preparing our capital budget. If NYMEX prices trend downward below our base deck, we may reevaluate capital projects and may adjust the capital budgeted for development, exploitation, and exploration investments accordingly.

Development, exploitation, and exploration of existing properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities during the year ended December 31, 2005 and 2004 (in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Development and exploitation	$ 236,467	$ 117,464	$ 86,078
HPAI	32,053	39,628	12,899
Exploration	57,046	30,546	
Total	$ 325,566	$ 187,638	$ 98,977

Development and exploitation. Our expenditures for development and exploitation investments primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities (excluding development-related asset retirement obligations). Our development and exploitation capital for 2005 included a total of 242 gross (144.4 net) successful wells and 4 gross (2.2 net) developmental dry holes.

For 2006, we have budgeted $176.0 million for development and exploitation capital. We currently have 13 operated rigs drilling on the onshore continental United States with 4 rigs in the CCA, 2 rigs in the Permian Basin, 3 rigs in Oklahoma, 1 rig in North Texas, and 3 rigs in East Texas.

Exploration. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. During 2005, our exploration capital was invested primarily in drilling extension wells in the CCA and Mid-Continent area and exploratory wells in the shallow gas zones of our acreage in north central Montana. In 2005, our exploration capital yielded 34 (22.1 net) exploratory wells that were productive and 47 gross (41.9 net) exploratory dry holes.

For 2006, we have budgeted $94.0 million for exploration capital.

High-pressure air injection. In the Pennel unit of the CCA, we have completed Phase 1 and Phase 2 of the HPAI project and are currently expanding to the Phase 3 portion of the project. In April 2005, we installed a new HPAI facility capable of injecting 60 million cubic feet per day into the Pennel and Coral Creek units of the CCA, giving Encore the capacity to complete the development of these units. The Pennel Field is responding to the air injection as expected with a 400 barrel of oil per day increase over the forecasted production decline prior to the initiation of the project.

High-pressure air injection in the Little Beaver unit of the CCA was initiated in late 2003, and full implementation of the project was completed in the fourth quarter of 2004. Through 2005, the program has added proved reserves of approximately 15 million BOE to the Little Beaver unit. We continue to see positive production response in line with expectations with a 800 barrel of oil per day increase over the forecasted production decline prior to the initiation of the project.

For 2006, we have budgeted $32.0 million for high-pressure air injection capital.

Acquisitions, Leasehold and Acreage Costs. The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas property acquisitions during the year ended December 31, 2005 and 2004 (in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Acquisitions	$ 224,469	$ 204,907	$ 54,484

Leasehold acreage costs	21,205	33,926	117
Total	$ 245,674	$ 238,833	$ 54,601

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2005 Acquisitions. On October 14, 2005, we completed the acquisition of Crusader Energy Corporation for a purchase price of approximately $109.7 million, which includes acquired working capital. The acquired properties are located primarily in the western Anadarko Basin and the Golden Trend area of Oklahoma.

On November 30, 2005, we acquired oil and natural gas properties from Kerr-McGee Corporation for a purchase price of approximately $101.4 million. The acquired properties are located in the Levelland-Slaughter, Howard Glasscock, Nolley-McFarland and Hutex fields in West Texas and the Oakdale, Calumet and Rush Springs fields in western Oklahoma.

On September 8, 2005, we acquired oil and natural gas properties in the Williston Basin for a purchase price of approximately $28.6 million.

In addition to these acquisitions, we invested approximately $12.2 million during 2005 in additional working interests spread over our various core areas.

2004 Acquisitions. On April 14, 2004, we completed the acquisition of Cortez Oil & Gas, Inc. for a purchase price of approximately $127.0 million. The acquired properties are located in the CCA of Montana, the Permian Basin of west Texas and southeastern New Mexico, and in the Mid-Continent area. On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million.

We do not budget for acquisitions but we will continue to evaluate acquisition opportunities as they arise in 2006 with the same disciplined commitment to acquire assets that fit our portfolio and continue to create value. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio. Because of the current high oil price environment, acquiring good quality oil and natural gas properties that are predictable, exploitable, and profitable is increasingly difficult. Success in the acquisition market depends largely on the level of competition in the marketplace and the availability of properties for sale.

Leasehold acreage costs. Our capital expenditures for leasehold acreage costs during the years ended December 31, 2005, 2004, and 2003 totaled $21.2 million, $33.9 million, and $0.1 million, respectively. Leasehold costs incurred in 2005 consist primarily of $14.3 million of undeveloped leasehold costs for acreage spread over our various core areas and $6.9 million related to leases acquired in the Crusader acquisition.

Leasehold costs incurred in 2004 relate primarily to the Cortez, Overton, and Montana shallow gas acreage acquisitions during the year. Of the $33.9 million of capital expenditures for unproved property in 2004, $3.0 million and $18.4 million relate to the Cortez and Overton acquisitions, respectively, $7.9 million relates to leases acquired in our Montana shallow gas area, and the remaining $4.6 million relates to unproved acreage spread over our other core areas.

For 2006, we expect to invest $11.3 million for the acquisition of leasehold acreage costs primarily in our core areas.

Other General Property and Equipment. Our capital expenditures for other general property and equipment during the years ended December 31, 2005, 2004, and 2003 totaled $6.8 million, $7.6 million, and $1.5 million, respectively. Capital expenditures for other general property and equipment include aircraft, corporate leasehold improvements, computers, and various equipment.

For 2006, we expect to invest $6.0 million in other general property and equipment.

Funding of necessary working capital. At December 31, 2005, our working capital was $(56.8) million while at December 31, 2004, our working capital was $(15.6) million, a decrease of $41.2 million. At December 31, 2003, working capital was $(0.1) million. The decreases from year to year are primarily attributable to changes in the fair value of outstanding derivative contracts, net of the deferred tax effect of marking these contracts to market.

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For 2006, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our derivative contracts, the settlements of which will be offset by cash flows from the hedged production. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and pay down our revolving credit facility. We do not plan to pay cash dividends in the foreseeable future. The overall 2006 commodity prices and our related differentials for oil and natural gas will be the largest variable driving the different components of working capital. Our operating cash flow is determined in large part by commodity prices. Assuming moderate to high commodity prices, our operating cash flow should remain positive for the foreseeable future.

Our Board of Directors has approved budgeted capital expenditures of approximately $320.0 million for 2006. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and borrowings under our existing revolving credit agreement.

Contractual Obligations. The following table illustrates our contractual obligations and commitments outstanding at December 31, 2005 (in thousands):

	Payments Due by Period				
Contractual Obligations and Commitments	**Total**	**2006**	**2007 - 2008**	**2009 - 2010**	**Thereafter**
$6^1/4$% notes(a)	$ 229,675	$ 9,375	$ 18,750	$ 18,750	$ 182,800
6% notes(a)	480,000	18,000	36,000	36,000	390,000
$7^1/4$% notes(a)	280,500	10,875	21,750	21,750	226,125
Revolving credit facility(a)	105,760	5,152	10,304	90,304	
Derivative obligations(b)	140,625	74,063	66,562		
Development commitments(c)(f)	41,706	41,106	600		
Operating leases(d)	11,716	1,918	3,007	2,755	4,036
Asset retirement obligations(e)	118,078	582	1,165	1,165	115,166
Total	$ 1,408,060	$ 161,071	$ 158,138	$ 170,724	$ 918,127

(a) Amounts included in the table above include both principal and projected interest payments. See information presented in Note 8. Long-Term Debt to the accompanying consolidated financial statements for additional information regarding our long-term debt.

(b) Derivative obligations represent liabilities for derivatives that were valued as of December 31, 2005. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 13. Financial Instruments to the accompanying consolidated financial statements for additional information regarding our derivative obligations.

(c) Development commitments represent authorized purchases, $40.4 million of which represents work in process and is accrued at December 31, 2005. At December 31, 2005, we had $237.3 million of authorized purchases not placed to vendors (authorized AFEs) which were not accrued at year-end, but are budgeted for and expected to be made during 2006 unless circumstances change. Development commitments in the above table also include future minimum payments for electricity and seismic data analysis.

(d) Operating leases represent office space and equipment obligations that have remaining non-cancelable lease terms in excess of one year. See Note 4. Commitments and Contingencies to the accompanying consolidated financial statements for additional information regarding our operating leases.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the completion of field life. See

Note 5. Asset Retirement Obligations to the accompanying consolidated financial statements for additional information regarding our asset retirement obligations.

(f) Subsequent to December 31, 2005, we entered into drilling rig commitments that require total payments of approximately $116 million over a two year period.

Other Contingencies and Commitments. In order to facilitate ongoing sales of our oil production in the CCA, we ship a portion of our production in pipelines downstream and sell to purchasers at major U.S. market hubs. From time to time, shipping delays or purchaser stipulations may require that we sell our oil production in periods subsequent to the period in which it is produced. In such case, the deferred sale would have an adverse effect in the period of production on reported production volumes, revenues, and costs as measured on a unit-of-production basis.

The sale of our CCA oil production is dependent on transportation through Butte Pipeline to markets in the Guernsey, Wyoming area. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and subject to apportionment since December 2005, we have been able to move our produced volumes through Platte Pipeline. However, further restrictions on the available capacity to transport through these pipelines could have a material adverse effect on price received, production volumes, and revenues.

In the fourth quarter of 2005, the differential between our average oil wellhead price and the average NYMEX oil price widened. We expect this differential to continue to widen in the first half of 2006 due to market circumstances in the Rocky Mountain area, which is expected to adversely affect the wellhead price we receive in the CCA. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited takeaway capacity from the Rocky Mountain area, have gradually widened the differential between our wellhead price and the benchmark NYMEX price at Cushing, Oklahoma. A particularly active turnaround season in the first quarter of 2006 on the part of the Rocky Mountain area refiners has led to a further widening of the differential. We cannot accurately predict crude oil differentials for subsequent quarters.

Letters of Credit. As of December 31, 2005, we had $50.0 million in letters of credit posted with two of our commodity derivative contract counterparties. At any point in time, we have hedge margin deposits and letters of credit equal to the amount by which the current mark-to-market liability of our commodity derivative contracts exceeds the margin maintenance thresholds we have negotiated with our counterparties. Once a margin threshold is reached, we are required to maintain cash reserves in an account with the counterparty or post letters of credit in lieu of cash to ensure future settlement is made pursuant to our contracts. These funds are released back to us as our mark-to-market liability decreases due to either a drop in the futures price of oil and natural gas or due to the passage of time as settlements are made. Although we did not have any margin deposits with our counterparties as of December 31, 2005, if commodity prices were to rise substantially, we would be required to post margin with one or more counterparties to secure future hedging settlements. As of March 3, 2006, we did not have any outstanding hedge margin deposits related to our derivatives margin accounts. As of March 3, 2006, we had $50.0 million of outstanding letters of credit posted in lieu of cash margin deposits.

Liquidity

Cash on hand, internally generated cash flows and the borrowing capacity under our revolving credit facility are our major sources of liquidity. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

Internally generated cash flows. Our internally generated cash flows, results of operations and financing for our operations are dependent on oil and natural gas prices and our related price differentials. Realized oil and natural gas prices for 2005 were 33% higher as compared to 2004. These prices have historically fluctuated widely in response to changing market forces. For the year ended December 31, 2005, approximately 66% of our production was oil. We believe that our cash flows and unused availability under our revolving credit facility are sufficient to fund our planned capital expenditures for the foreseeable future. To the extent oil and natural gas prices decline, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of low oil and natural gas prices could cause us to not be in compliance with covenants under our revolving credit facility and thereby affect our liquidity.

Revolving credit facility. Our principal source of short-term liquidity is our revolving credit facility. The revolving credit facility is with a bank syndicate comprised of Bank of America, N.A. and other lenders. The borrowing base is determined semi-annually and may be increased or decreased, up to a maximum of $750.0 million. The borrowing base as of December 31, 2005 was $550.0 million. At various times in 2005, we amended the revolving credit facility to change the borrowing base, allow additional permitted subordinated debt, change the definition of EBITDA to add back exploration expense (EBITDAX), increase the availability of letters of credit from 15% of the borrowing base to 20%, and extend the original maturity date. The revolving credit facility matures on December 29, 2010.

Our obligations under the revolving credit facility are guaranteed by our restricted subsidiaries and secured by a first priority-lien on substantially all of our proved oil and natural gas reserves and a pledge of the capital stock and equity interests of our restricted subsidiaries.

Amounts outstanding under the revolving credit facility are subject to varying rates of interest based on (1) the amount outstanding under the amended and restated credit facility in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. The following table summarizes the calculation of the various interest rates for both Eurodollar and Base Rate loans:

Ratio of Total Outstanding to Borrowing Base	Eurodollar Loans(a)	Base Rate Loans(b)
Less than .40 to 1	LIBOR + 1.000%	Base Rate + 0.000%
From .40 to 1 but less than .75 to 1	LIBOR + 1.250%	Base Rate + 0.000%
From .75 to 1 but less than .90 to 1	LIBOR + 1.500%	Base Rate + 0.250%
.90 to 1 or greater	LIBOR + 1.750%	Base Rate + 0.500%

(a) The LIBOR rate is equal to the rate determined by Bank of America, N.A. to be the British Bankers Association Interest Settlement Rate for deposits in dollars for a similar interest period (either one, two, three or six months, or such other period as selected by Encore, subject to availability at each lender).

(b) The Base Rate is calculated as the highest of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5%.

The borrowing base is redetermined each April 1 and October 1. The bank syndicate has the ability to request one additional borrowing base redetermination per year, and we are permitted to request two additional borrowing base redeterminations per year. Generally, if amounts outstanding ever exceed the borrowing base, we must reduce the amounts outstanding to the redetermined borrowing base within six months, provided that if amounts outstanding exceed the borrowing base as a result of any sale of our assets or permitted subordinated debt, we must reduce the amounts outstanding immediately upon consummation of the sale.

Borrowings under the revolving credit facility may be repaid at anytime without penalty.

Our revolving credit facility and the indentures related to our $6^1/4$%, 6%, and $7^1/4$% notes contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. The covenants under our revolving credit facility are similar but generally more restrictive than the covenants under the indentures. Our ability to borrow under our revolving credit facility is subject to financial covenants, including leverage, interest and fixed charge coverage ratios. Our revolving credit facility limits our ability to effect mergers, asset sales, and change of control events. These

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covenants also contain restrictions regarding our ability to incur additional indebtedness in the future. In some cases, our subsidiaries are subject to similar restrictions that may restrict their ability to make distributions to us. The indentures related to our 6 1/4%, 6%, and 7 1/4% notes also contain limitations on our ability to effect mergers and change of control events, incur additional indebtedness, sell assets, declare and pay dividends or make other restricted payments, enter into transactions with affiliates and subject our assets to liens.

On December 31, 2005, we had $80.0 million outstanding under the credit facility. On March 3, 2006, we had $90.0 million outstanding under the credit facility.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that are material to our financial position or results of operations.

Inflation and Changes in Prices

Our revenues, the value of our assets, and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and natural gas prices. Historically, significant fluctuations have occurred in oil and natural gas prices. The following table indicates the average oil and natural gas prices received for the years ended December 31, 2005, 2004, and 2003. Average equivalent prices for 2005, 2004, and 2003 were decreased by $5.71, $4.21, and $1.89 per BOE, respectively, as a result of our hedging activities. Average prices per equivalent barrel indicate the composite impact of changes in oil and natural gas prices. Natural gas production is converted to oil equivalents at the conversion rate of six Mcf per Bbl.

	Oil ($/Bbl)	Natural Gas ($/Mcf)	Combined ($/BOE)
Net Price Realization with Hedges			
Year ended December 31, 2005	$ 44.82	$ 7.09	$ 44.05
Year ended December 31, 2004	33.04	5.53	33.07
Year ended December 31, 2003	26.72	4.83	27.14
Average Wellhead Price			
Year ended December 31, 2005	$ 51.06	$ 7.87	$ 49.76
Year ended December 31, 2004	38.24	5.76	37.28
Year ended December 31, 2003	28.82	5.00	29.03

The increase in oil and natural gas prices may be accompanied by or result in increased well drilling costs, as the demand for well drilling operations continues to increase; increased severance taxes, as we are subject to higher severance taxes due to the increased value of oil and natural gas extracted from the wells; increased lease operating expenses due to increased demand for services related to operating our wells; and increased electricity costs. We believe our risk management program and available borrowing capacity under our revolving credit facility provide means for us to manage commodity price risks through our hedging program.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made, and changes in the estimate or different estimates that could have been selected could have a material impact on Encore s consolidated results of operations or financial condition. Management has identified the following critical accounting policies and estimates.

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Oil and Natural Gas Properties

Successful efforts method. We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of the Consolidated Statement of Cash Flows. Capitalized drilling costs related to exploratory wells shall continue to be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress has been made to assess the reserves and the economic and operating viability of the project. If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed as Exploration Expense in the Consolidated Statement of Operations and shown as a non-cash adjustment to net income in the Operating activities section of the Consolidated Statement of Cash Flows in the period in which the determination was made. Expenditures for redrilling or directional drilling in a previously abandoned well are classified as drilling costs to a proven or unproven reservoir for determination of capital or expense. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different or additional proven or unproven reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil at the rate of six Mcf to one barrel.

Unproved Properties. We adhere to Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider the remaining lease terms along with various subjective assumptions involving geologic and engineering factors to evaluate the need for impairment of these costs. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance. Unproved properties had a net book value of $37.6 million and $29.7 million as of December 31, 2005 and 2004, respectively. We recorded charges for unproved acreage impairment in the amounts of $2.0 million, $0.7 million, and $0.4 million in 2005, 2004, and 2003, respectively.

Oil and Natural Gas Reserves. Assumptions used by the independent reserve engineers in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. The accuracy of reserve estimates is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the independent reserve engineer. Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. We may not be able to develop proved reserves within the periods estimated. Furthermore, prices and costs will not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, the amount of calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, the property s fair value, and our depletion rate.

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Impairment. Impairments of proved oil and natural gas properties are directly affected by our reserve estimates. We are required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Each part of this calculation is subject to a large degree of management judgment, including the determination of the property s reserves, the amount and timing of future cash flows, and fair value.

Asset Retirement Obligations. Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and natural gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment costs, annual inflation of these costs, the productive life of the asset and our risk adjusted costs to settle such obligations discounted using our risk-adjusted interest rate, which is calculated based on comparisons of our current borrowing rate to U.S Treasury rates of a similar maturity. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the obligation are recorded with an offsetting change to the carrying amount of the related oil and natural gas properties asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of the liability. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Depletion, Depreciation, and Amortization (DD&A). DD&A expense is directly affected by our reserve estimates. Any change in reserves directly impacts the amount of DD&A expense that we recognize in a given period. Assuming no other changes, such as an increase in depreciable base, as our reserves increase, the amount of DD&A expense in a given period decreases and vice versa. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves. DD&A expense associated with lease and well equipment and intangible drilling costs are based upon only proved developed reserves, while DD&A expense for capitalized leasehold costs is based upon total proved reserves. As a result, changes in the classification of our reserves could have a material impact on our DD&A expense. Additionally, Miller & Lents, Ltd., our independent reserve engineers, estimate our reserves once a year at December 31. As a result, quarterly reported DD&A expense is based on internally prepared estimates of reserves additions and reclassifications to the December 31 amounts prepared by Miller & Lents, Ltd.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchases of Cortez Oil & Gas, Inc. in April 2004 and of Crusader Energy Corporation in October 2005 (see Note 3, Acquisitions). We test goodwill for impairment on an annual basis or whenever indicators of impairment exist. We performed our annual impairment test at December 31, 2005, and determined that no impairment existed. If impairment is determined to exist, we will measure our impairment based on a comparison of the carrying value of goodwill to the implied fair value of the goodwill. We would recognize an impairment charge for any amount by which the carrying value of goodwill exceeds its fair value.

We allocate the purchase price paid for the acquisition of a business to the assets and liabilities acquired based on the estimated fair values of those assets and liabilities. Estimates of fair value are based upon, among other things, reserve estimates, anticipated future prices and costs, and expected net cash flows to be generated by a property. These estimates are often highly subjective and may have a material impact on the amounts recorded for acquired assets and liabilities.

Net Profits Interests

A major portion of our acreage position in the Cedar Creek Anticline is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been deducted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the NPIs and will have an inverse effect on our reported reserves and production. Based largely on a continued increase in commodity prices, we expect to make higher net profit interest payments in 2006 and possibly beyond than we have in previous years, which directly impacts our revenues, production, reserves, and net income.

Revenue Recognition

Revenues are recognized for our share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Natural gas revenues are also reduced by any processing and other fees paid except for transportation costs paid to third parties which are recorded as expense. Natural gas revenue is recorded using the sales method of accounting whereby revenue is recognized as natural gas is sold rather than as it is produced. Royalties, net profits interests, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, we estimate and record the expected sales volumes and price for those properties. We also do not recognize revenue for the production in tanks, purchased oil marketed on behalf of third parties, or oil in pipelines that has not been delivered to the purchaser yet. Our net oil inventories in pipelines were 49,543 Bbls and 44,901 Bbls at December 31, 2005 and 2004, respectively. Natural gas imbalances at December 31, 2005 and December 31, 2004, were 204,400 MMBTU over delivered to us and 259,500 MMBTU under delivered to us, respectively.

Income Taxes

Section 43 Credits. Section 43 of the Internal Revenue Code (the Code) allows a 15 percent tax credit for certain enhanced oil recovery project costs incurred in the United States. We believe project costs incurred related to our HPAI tertiary recovery project on the CCA qualify under the provisions of the Code and, therefore, we have reduced income tax expense by 15 percent of project costs incurred to date. The tax basis for the properties (and related intangible drilling cost deductions and future depreciation deductions) is reduced by the amount of the enhanced oil recovery tax credit. In order to qualify for the credits a project must meet all of the following requirements:

1. The project involves the application of one or more qualified tertiary recovery methods that is reasonably expected to result in more than an insignificant increase in the amount of oil that ultimately will be recovered;

2. The project is located within the United States;

3. The first injection of liquids, gases, or other matter for the project occurs after December 31, 1990; and

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4. The project is certified by a petroleum engineer.

According to the Code, the costs that will qualify for the credit when paid or incurred in connection with a qualifying enhanced oil recovery project include:

1. *Tangible Property.* Any amount paid for tangible property that is an integral part of a qualified enhanced oil recovery project, and with respect to which depreciation is allowable.

2. *Intangible Drilling and Development Costs.* Intangible drilling cost with respect to which the taxpayer may make an intangible drilling costs deduction election under Code Sec. 263(c).

3. *Qualified Tertiary Injectant Expenses.* Any qualified tertiary injectant expenses for which a deduction is allowable under any Code section.

If our federal income tax returns are reviewed by the Internal Revenue Service (the IRS), the IRS could disagree with our decision and disallow a portion of the credit. While we believe our HPAI project qualifies for the tax credit and that our accounting and tracking of the costs related to the project are accurate, should the IRS disagree with our position, we would be required to record additional income tax expense to the extent income tax expense has previously been reduced related to the generation of Section 43 credits.

Effective Tax Rate. Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax paying companies. Currently, our effective tax rate varies primarily as the amount of Section 43 income tax credits generated varies from period to period. These credits are generated by paying or incurring certain costs in connection with a qualifying enhanced oil recovery project, such as our current high-pressure air injection projects underway in the CCA. Our effective tax rate is also affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state.

Hedging and Related Activities

We use various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our oil and natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter forward derivative contracts executed with large financial institutions. We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation.

We currently recognize all of our derivative and hedging instruments in our statements of financial position as either assets or liabilities and measure them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. Most of our derivative financial instruments qualify for hedge accounting. Cash flow hedges are marked-to-market through comprehensive income each quarter.

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in Other Comprehensive Income in Stockholders Equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the gain or loss is recognized as Derivative fair value (gain) loss in the Consolidated Statements of Operations immediately. While management does not anticipate changing the designation of any of our current derivative contracts as hedges, factors beyond our control can preclude the use of hedge accounting.

One example would be variability in the NYMEX price for oil or natural gas, upon which many of our commodity derivative contracts are based, that does not coincide with changes in the spot price for oil and natural gas that we are paid. As previously discussed, we expect the differential between our average oil wellhead price and the average NYMEX oil price to widen in the first half of 2006 due to market circumstances in the Rocky Mountain area, which is expected to adversely affect the wellhead price we receive in the CCA. This factor will result in additional ineffectiveness on hedges designated on our Rocky Mountain production and could ultimately preclude the use of hedge accounting. Assuming constant prices and based on our hedged position as of December 31, 2005, a 10% and 25% increase in the oil and natural gas wellhead differentials would result in increases to our derivative fair value loss in 2006 of approximately 54% and 106%, respectively.

Another example would be if the counterparty to a derivative contract was deemed no longer creditworthy and non-performance under the terms of the contract was likely. To the extent our derivative contracts are not designated as hedges, high earnings volatility can result, as any future changes in the market value of the contract would then be marked-to-market through earnings.

New Accounting Standards

Statement of Financial Accounting Standards No. 123R, Share-Based Payment . In December 2004, the FASB issued Statement No. 123R, Share-Based Payment . SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supersedes APB 25. SFAS No. 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The effective date of SFAS No. 123R is January 1, 2006 for calendar year companies.

SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R, for all share-based payments granted after that date, and for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but it also permits entities to restate financial statements of previous periods based on pro-forma disclosures made in accordance with SFAS No. 123. We plan to adopt the requirements of SFAS No. 123R using the modified prospective method.

We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options when calculating the pro forma effect of applying the fair value provisions of SFAS No. 123. While SFAS No. 123R permits entities to continue to use such a model, the standard also permits the use of a lattice model. We plan to continue using a Black-Scholes option pricing model to measure the fair value of employee stock options upon the adoption of SFAS No. 123R.

Under SFAS No. 123R, the pro forma disclosures previously permitted under SFAS No. 123 will no longer be an alternative to financial statement recognition.

SFAS No. 123R also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated because they depend on, among other things, when employees exercise stock options and our stock price at that time.

In 2006 we expect to record total expense related to stock options granted prior to January 1, 2006 of approximately $1.3 million. We have not yet determined the financial statement impact of adopting SFAS No. 123R for options granted subsequent to December 31, 2005 because they depend on, among other things, the number of options granted in the future and our future stock price.

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations. In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. We adopted FIN No. 47 as of December 31, 2005. There was no material impact on our results of operations, financial condition, or cash flows.

FASB Staff Position 19-1, Accounting for Suspended Well Costs. We adopted FASB Staff Position (FSP) 19-1 Accounting for Suspended Well Costs on July 1, 2005. FSP 19-1 amends SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, to permit the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Upon the adoption of FSP 19-1, we evaluated all existing capitalized exploratory well costs and determined that there was no impact on our results of operations, financial condition, or cash flows. See Note 6. Capitalization of Exploratory Well Costs to the accompanying consolidated financial statements for additional information regarding FSP 19-1.

Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3. In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for our fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but we do not currently expect SFAS No. 154 to have a material impact on our results of operations, financial condition, or cash flows.

Emerging Issues Task Force (EITF) Issue 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty. The Emerging Issues Task Force considered Issue No. 04-13 in its May 17, 2005 and June 16, 2005 meetings to discuss inventory sales to another entity in the same line of business from which it also purchases inventory. The Task Force reached consensus on the issue that purchases and sales of inventory with the same counterparty should be combined as a single nonmonetary transaction (net) and noted factors that may indicate that transactions were entered into in contemplation of one another. The Task Force also concluded that transfers of finished goods inventory in exchange for work-in-progress or raw materials should be recognized at fair value and prescribes additional disclosures. The Task Force ratified Issue No. 04-13 at its September 28, 2005 meeting, which should be applied to new arrangements entered into in the first interim or annual reporting period beginning after March 15, 2006. We have previously reported transactions of this nature on a net basis; therefore, we do not expect Issue No. 04-13 to have a material impact on our results of operations, financial condition, or cash flows.

Information Concerning Forward-Looking Statements

This Report contains forward-looking statements, which give our current expectations or forecasts of future events. You can identify our forward-looking statements by the fact that they do not relate strictly

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to historical or current facts. These statements may include words such as anticipate, estimate, expect, project, int plan, believe, should and other words and terms of similar meaning. In particular, forward-looking statements included in this Report relate to, among other things, the following:

expected capital expenditures and the focus of our capital program;

areas of future growth;

our drilling program;

future horizontal development, secondary development and tertiary recovery potential;

the implementation of our high-pressure air injection program, the ability to expand the program to other parts of the CCA and the effects thereof;

the completion of current HPAI projects and the effects thereof;

anticipated prices for oil and natural gas and expectations regarding differentials between wellhead prices received and benchmark prices (including, without limitation, the effects of increased Canadian oil production and refinery turnarounds);

projected revenues; lifting costs; lease operations expenses; production, ad valorem and severance taxes; DD&A expense; general and administrative expenses; other operating expenses; and taxes;

timing and amount of future production of oil and natural gas;

availability of pipeline capacity;

expected hedging positions and payments related to hedging contracts (including the effectiveness thereof);

expectations regarding working capital, cash flow and anticipated liquidity;

projected borrowings under our revolving credit facility;

our ability to continue to use hedge accounting; and

marketing of oil and natural gas.

You are cautioned not to place undue reliance on such forward-looking statements, which speak only as of the date of this Report. Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed above under the caption Item 1A. Risk Factors and elsewhere in this Report and in our other filings with the Securities and Exchange Commission. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

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

Hedging policy. We have adopted a formal hedging policy. The purpose of our hedging program is to mitigate the negative effects of declining commodity prices on our business. We plan to continue in the normal course of business to hedge our exposure to fluctuating commodity prices. However, not all of our derivatives qualify for hedge accounting and in some instances management has determined it is more cost effective not to designate certain derivatives as hedges. In very limited circumstances, the Company may enter into derivative financial instruments to achieve other goals besides risk reduction. One example would be the use of a fixed to floating interest rate swap to offset interest expense on fixed rate debt. The Company weighs the increased risk of the instrument versus the potential cash flow savings before entering into any derivative instrument designed to achieve any goal other than risk reduction.

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Counterparties. Our counterparties to hedging contracts include: BNP Paribas; Calyon; Deutsche Bank; Mitsui & Co.; Morgan Stanley; Shell Trading; Wachovia; J. Aron & Company, BP Products, Bank of America, and Koch Supply and Trading. At December 31, 2005, our hedged oil and natural gas production was committed to the counterparties as follows:

Counterparty	Percentage of Hedged Oil Production Committed	Percentage of Hedged Natural Gas Production Committed
BNP Paribas		45%
Calyon	14%	20%
Deutsche Bank	37%	3%
J. Aron & Company	3%	23%
Morgan Stanley	11%	
Wachovia	23%	

Performance on all of our contracts with J. Aron & Company is guaranteed by its parent, Goldman Sachs & Co. We feel the credit-worthiness of our current counterparties is sound and we do not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating separately each financial transaction between our counterparty and us, the master netting agreement enables our counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement benefits us in three ways. First, the netting of the value of all trades reduces the requirements of daily collateral posting by us. Second, default by counterparty under one financial trade can trigger rights for us to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Commodity price sensitivity. The tables in this section provide information about derivative financial instruments to which we were a party as of December 31, 2005 that are sensitive to changes in oil and natural gas commodity prices.

We hedge commodity price risk with swap contracts, put contracts, and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide a floor price on a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, we may occasionally sell short put contracts with a strike price well below the floor price of the collar. These short put contracts do not qualify for hedge accounting under SFAS 133, and accordingly, the mark-to-market change in the value of these contracts is recorded as fair value gain/loss in the statements of operations. Thus, not all of our derivatives qualify for hedge accounting and in some instances management has determined it is more cost effective not to designate certain derivatives as hedges. The unrealized mark-to-market loss on our outstanding commodity derivatives at December 31, 2005 was approximately $(116.3) million. As of December 31, 2005, the fair market value of our oil derivative contracts designated as hedges was $(48.5) million and the fair market value of our natural gas derivative contracts designated as hedges was $(40.7) million.

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Oil Derivative Contracts at December 31, 2005

Period	Daily Floor Volume (Bbl)	Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Swap Price (per Bbl)	Fair Market Value (In thousands)
Jan. - June 2006	13,500	$ 44.07	1,000	$ 29.88	3,000	$ 37.27	$ (17,899)
July - Dec. 2006	13,000	45.00	1,000	29.88	3,000	37.27	(16,081)
Jan. - Dec 2007	8,000	53.75			3,000	36.75	(13,807)
Jan. - June 2008					1,000	58.59	(685)

Natural Gas Derivative Contracts at December 31, 2005

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (In thousands)
Jan. - Dec. 2006	32,500	$ 6.17	5,000	$ 5.68	12,500	$ 5.02	$ (28,463)
Jan. - Dec. 2007	22,500	6.96			10,000	4.99	(12,278)

Interest rate sensitivity. At December 31, 2005, we had total long-term debt of $673.2 million, which is recorded net of discount of $6.8 million. Of this amount, $150.0 million bears interest at a fixed rate of 6 1/4%, $300.0 million bears interest at a fixed rate of 6%, and $150.0 million bears interest at a fixed rate of 7 1/4%. The remaining outstanding long-term debt balance of $80.0 million is under our revolving credit facility and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if the LIBOR rate increased 1%, we would incur an additional $0.8 million of interest expense per year, and if the rate decreased 1%, we would incur $0.8 million less. Additionally, if the LIBOR rate increased 1%, we estimate the fair value of our fixed rate debt at December 31, 2005 would decrease from $574.5 million to $534.8 million, and if the rate decreased 1%, we estimate the fair value would increase to $618.1 million.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and this Report:

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Bbl/ D. One stock tank barrel of oil or other liquid hydrocarbons per day.

BOE. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

BOE/ D. One barrel of oil equivalent per day, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

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

Delay Rentals. Fees paid to the lessor of the oil and natural gas lease during the primary term of the lease prior to the commencement of production from a well.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within or in close proximity to an area of known production targeting existing reservoirs.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

High-pressure air injection (HPAI). High-pressure air injection involves utilizing compressors to inject air into previously produced oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

Horizontal Drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Lease Operations Expense. All direct and indirect costs of producing oil and natural gas after completion of drilling and before removal of production from the property. Such costs include labor, superintendence, supplies, repairs, maintenance, and direct overhead charges.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

Mcf. One thousand cubic feet of natural gas.

Mcf/ D. One thousand cubic feet of natural gas per day.

Mcfe. One thousand cubic feet of natural gas equivalent, calculated by converting oil to natural gas equivalent at a ratio of one Bbl of oil to six Mcf.

MMBOE. One million barrels of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

MMBtu. One million British thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

MMcf. One million cubic feet of natural gas.

Net Acres or Net Wells. Gross acres or wells multiplied, as the case may be, by the percentage working interest owned by us.

Net Production. Production that is owned by us less royalties and production due others.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil or condensate.

Operating Income. Gross oil and natural gas revenue less applicable production taxes and lease operating expense.

Operator. The individual or company responsible for the exploration, exploitation, and production of an oil or natural gas well or lease.

Present Value of Future Net Revenues or Present Value or PV-10. The pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depletion, depreciation, and amortization, and discounted using an annual discount rate of 10%.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions.

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Proved Undeveloped Reserves. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on acreage yet to be drilled for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production. Proved undeveloped reserves include unrealized production response from fluid injection and other improved recovery techniques, such as high-pressure air injection, where such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reserve-To-Production Index or R/ P Index. An estimate expressed in years of the total estimated proved reserves attributable to a producing property divided by production from the property for the 12 months preceding the date as of which the proved reserves were estimated.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized Measure. Future cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized measure differs from PV-10 because standardized measure includes the effect of asset retirement obligations and future income taxes.

Tertiary Recovery. An enhanced recovery operation that normally occurs after waterflooding in which chemicals or natural gasses are used as the injectant. HPAI is a form of tertiary recovery.

Unit. A specifically defined area within which acreage is treated as a single consolidated lease for operations and for allocations of costs and benefits without regard to ownership of the acreage. Units are established for the purpose of recovering oil and natural gas from specified zones or formations.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Encore Acquisition Company:

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company and subsidiaries (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2005. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 3, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
March 3, 2006

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ENCORE ACQUISITION COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,654	$ 1,103
Accounts receivable	76,960	43,839
Inventory	11,231	6,550
Derivatives	8,826	2,665
Deferred taxes	29,030	11,118
Other	5,656	5,842
Total current assets	133,357	71,117
Properties and equipment, at cost successful efforts method:		
Proved properties	1,691,175	1,134,220
Unproved properties	37,646	29,740
Accumulated depletion, depreciation, and amortization	(255,564)	(171,691)
	1,473,257	992,269
Other property and equipment	15,894	10,425
Accumulated depreciation	(5,366)	(3,551)
	10,528	6,874
Goodwill	59,046	37,995
Derivatives	17,316	1,150
Other	12,201	13,995
Total assets	$ 1,705,705	$ 1,123,400
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 27,281	$ 24,375
Accrued lease operations expense	6,633	3,408
Accrued development capital	38,899	14,643
Derivatives	68,850	24,270
Production and severance taxes payable	12,566	9,106
Deferred premiums on derivative contracts	7,665	
Other	28,301	10,881

Total current liabilities		190,195		86,683
Derivatives		44,087		31,477
Future abandonment cost		14,430		6,601
Deferred taxes		213,268		146,064
Long-term debt		673,189		379,000
Deferred premiums on derivative contracts		22,476		
Other		1,279		
Total liabilities		1,158,924		649,825
Commitments and contingencies				
Stockholders equity:				
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding				
Common stock, $.01 par value, 144,000,000 shares authorized, 49,368,120 and 48,982,197 issued and outstanding, respectively		494		490
Additional paid-in capital		325,620		314,573
Treasury stock, at cost, of 11,169 and 0 shares, respectively		(375)		
Deferred compensation		(9,007)		(4,603)
Retained earnings		302,875		199,512
Accumulated other comprehensive income		(72,826)		(36,397)
Total stockholders equity		546,781		473,575
Total liabilities and stockholders equity	$	1,705,705	$	1,123,400

The accompanying notes are an integral part of these consolidated financial statements.

ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2005	2004	2003
	(In thousands except per share data)		
Revenues:			
Oil	$ 307,959	$ 220,649	$ 176,351
Natural gas	149,365	77,884	43,745
Total revenues	457,324	298,533	220,096
Expenses:			
Production			
Lease operations	68,395	47,142	37,846
Production, ad valorem, and severance taxes	45,601	30,313	22,013
Depletion, depreciation, and amortization	85,627	48,522	33,530
Exploration	14,402	3,907	
General and administrative (excluding non-cash stock based compensation)	14,696	10,982	8,680
Non-cash stock based compensation	3,962	1,770	614
Derivative fair value (gain) loss	5,290	5,011	(885)
Loss on early redemption of debt	19,477		
Other operating	9,485	5,028	3,481
Total expenses	266,935	152,675	105,279
Operating income	190,389	145,858	114,817
Other income (expenses):			
Interest	(34,055)	(23,459)	(16,151)
Other	1,039	240	214
Total other income (expenses)	(33,016)	(23,219)	(15,937)
Income before income taxes and cumulative effect of accounting change	157,373	122,639	98,880
Current income tax benefit (provision)	2,084	(1,913)	(991)
Deferred income tax provision	(56,032)	(38,579)	(35,111)
Income before cumulative effect of accounting change	103,425	82,147	62,778
Cumulative effect of accounting change, net of income taxes			863
Net income	$ 103,425	$ 82,147	$ 63,641

Income before cumulative effect of accounting change per common share:						
Basic	$	2.12	$	1.74	$	1.39
Diluted		2.09		1.72		1.38
Net income per common share:						
Basic	$	2.12	$	1.74	$	1.41
Diluted		2.09		1.72		1.40
Weighted average common shares outstanding:						
Basic		48,682		47,090		45,153
Diluted		49,522		47,738		45,500

The accompanying notes are an integral part of these consolidated financial statements.

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Shares of Common Stock	Common Stock	Additional Paid-In Capital	Shares of Treasury Stock	Treasury Stock	Deferred Compensation	Retained Earnings	Accumulated Other Comprehensive Income	Total Stockholders Equity
	(In thousands except share data)								
Balance at December 31, 2002	45,245	$ 452	$ 251,081		$	$ (2,396)	$ 53,724	$ (6,595)	$ 296,266
Exercise of stock options	218	2	1,973						1,975
Issuance of common stock	13,590	136	175,338						175,474
Purchase of treasury stock				(13,588)	(175,560)				(175,560)
Cancellation of treasury stock	(13,590)	(136)	(175,424)	13,588	175,560				
Deferred compensation:									
Issuance of restricted common stock	67	1	926			(927)			
Amortization to expense						614			614
Other changes	(26)		(181)			181			
Components of comprehensive income:									
Net income							63,641		63,641
Change in deferred hedge gain/loss (Net of income taxes of $2,105)								(3,435)	(3,435)
Total comprehensive income									60,206
Balance at December 31, 2003	45,504	455	253,713			(2,528)	117,365	(10,030)	358,975
	303	3	4,118						4,121

Exercise of stock options									
Issuance of common stock	3,000	30	52,899						52,929
Deferred compensation:									
Issuance of restricted common stock	189	2	3,371			(3,373)			
Amortization to expense						1,770			1,770
Other changes	(14)		472			(472)			
Components of comprehensive income:									
Net income							82,147		82,147
Change in deferred hedge gain/loss (Net of income taxes of $15,757)								(26,367)	(26,367)
Total comprehensive income									55,780
Balance at December 31, 2004	48,982	490	314,573			(4,603)	199,512	(36,397)	473,575
Exercise of stock options and vesting of restricted stock	138	1	2,817						2,818
Purchase of treasury stock				(18)	(570)				(570)
Cancellation of treasury stock	(7)		(133)	7	195		(62)		
Deferred compensation:									
Issuance of restricted common stock	286	3	7,645			(7,648)			
Amortization to expense						3,962			3,962
Other changes	(31)		718			(718)			

Components of comprehensive income:									
Net income							103,425		103,425
Change in deferred hedge gain/loss (Net of income taxes of $21,701)								(36,429)	(36,429)
Total comprehensive income									66,996
Balance at December 31, 2005	49,368	$ 494	$ 325,620	(11)	$ (375)	$ (9,007)	$ 302,875	$ (72,826)	$ 546,781

The accompanying notes are an integral part of these consolidated financial statements.

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Operating activities			
Net income	$ 103,425	$ 82,147	$ 63,641
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, and amortization	85,627	48,522	33,530
Dry hole expense	8,667	2,086	
Deferred taxes	56,032	38,579	35,111
Non-cash stock based compensation	3,962	1,770	614
Cumulative effect of accounting change			(863)
Loss on early redemption of debt	19,477		
Non-cash derivative fair value (gain) loss	12,637	12,449	(165)
Other non-cash	3,951	1,456	1,293
Loss on disposition of assets	352	271	322
Changes in operating assets and liabilities:			
Accounts receivable	(30,192)	(10,719)	(5,602)
Other current assets	(6,096)	(7,220)	(8,592)
Other assets	(4,798)	(5,568)	(2,024)
Accounts payable and other current liabilities	39,225	8,048	6,553
Cash provided by operating activities	292,269	171,821	123,818
Investing Activities			
Proceeds from disposition of assets	753	703	1,295
Purchases of other property and equipment	(6,767)	(7,594)	(1,464)
Acquisition of oil and natural gas properties	(154,615)	(116,316)	(54,601)
Acquisition of Cortez Oil & Gas, Inc. (net of cash acquired)		(123,808)	
Acquisition of Crusader Energy Corp. (net of cash acquired)	(91,095)		
Development of oil and natural gas properties	(321,836)	(186,455)	(98,977)
Cash used by investing activities	(573,560)	(433,470)	(153,747)
Financing Activities			
Proceeds from issuance of common stock		53,900	176,127
Purchase of treasury stock	(570)		(175,560)
Offering costs paid		(971)	(653)
Proceeds from issuance of $6^1/4$% notes		150,000	
Proceeds from issuance of 6% notes	294,480		
Proceeds from issuance of $7^1/4$% notes	148,500		
Redemption of $8^3/8$% notes	(165,852)		

Payments for debt issuance costs	(534)	(4,808)	(125)
Exercise of stock options	1,468	2,756	1,975
Proceeds from long-term debt	555,000	328,500	112,500
Payments on long-term debt	(554,000)	(278,500)	(99,500)
Cash overdrafts	3,350	11,444	2,539
Cash provided by financing activities	281,842	262,321	17,303
Increase (decrease) in cash and cash equivalents	551	672	(12,626)
Cash and cash equivalents, beginning of period	1,103	431	13,057
Cash and cash equivalents, end of period	$ 1,654	$ 1,103	$ 431

The accompanying notes are an integral part of these consolidated financial statements.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Formation of the Company and Basis of Presentation

Encore Acquisition Company, a Delaware corporation (Encore or the Company), is a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since the Company s inception in 1998, Encore has sought to acquire high-quality assets with potential for upside through low-risk development drilling projects. Encore s properties are currently located in four core areas: the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and Southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of north Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana and North Dakota, and the Paradox Basin of southeastern Utah.

Certain balances reported in prior periods have been reclassified to conform prior year data to the current year presentation.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of all of our subsidiaries. All material intercompany balances and transactions are eliminated.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks, money market accounts, and all highly liquid investments with an original maturity of three months or less. On a bank-by-bank basis, cash accounts that are overdrawn are reclassified to current liabilities and any change in cash overdrafts is shown as Cash overdrafts in the Financing Activities section of the Consolidated Statements of Cash Flows.

Inventories

Inventories are comprised principally of materials and supplies and oil in pipelines, which are stated at the lower of cost (determined on an average basis) or market. Oil produced at the lease which resides unsold in pipelines is carried at an amount equal to its operating costs to produce. Oil in pipelines purchased from third parties is carried at average purchase price. The Company s inventories consisted of the following at December 31 (amounts in thousands):

	2005	2004
Warehouse inventory	$ 9,019	$ 6,321
Oil in pipelines	2,212	229
Total	$ 11,231	$ 6,550

Properties and Equipment

Oil and Natural Gas Properties

The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of the Consolidated Statement of Cash Flows. If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in the Consolidated Statement of Operations and shown as a non-cash adjustment to net income in the Operating activities section of the Consolidated Statement of Cash Flows in the period in which the determination was made. If a determination cannot be made within one year of the exploration well being drilled and no other drilling or exploration activities to evaluate the discovery are firmly planned, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income at that time. Expenditures for redrilling or directional drilling in a previously abandoned well are classified as drilling costs to a proven or unproven reservoir for determination of capital or expense. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different or additional proven or unproven reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in the Company s consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil at the rate of six Mcf to one barrel.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to the accumulated depletion, depreciation, and amortization reserve. Gains or losses from the disposal of other properties are recognized in the current period.

Additionally, the Company s independent reserve engineers estimate our reserves once a year on December 31. This results in a new DD&A rate which the Company uses for the preceding fourth quarter after adjusting for fourth quarter production. The Company internally estimates its reserve additions and reclassifications of reserves from proved undeveloped to proved developed each quarter to determine quarterly DD&A expense.

Unproved Properties

The Company adheres to Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. The Company considers the remaining lease terms along with various subjective assumptions involving geologic and engineering factors to evaluate the need for impairment of these costs. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance. Unproved properties had a net book value of $37.6 million and $29.7 million as of December 31, 2005 and 2004, respectively. The Company recorded charges for unproved acreage impairment in the amounts of $2.0 million, $0.7 million, and $0.4 million in 2005, 2004, and 2003, respectively.

Other Property and Equipment

Other property and equipment are carried at cost. Depreciation and amortization are provided on a straight-line basis over their estimated useful lives, which range from three to ten years.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchases of Crusader Energy Corporation in October 2005 and Cortez Oil & Gas, Inc. in April 2004 (see Note 3. Acquisitions). The Company tests goodwill for impairment on an annual basis or whenever indicators of impairment exist. The Company performed its annual impairment test at December 31, 2005, and determined that no impairment existed. If impairment is determined to exist, the impairment is measured based on a comparison of the carrying value of goodwill to the implied fair value of the goodwill. An impairment charge would be recognized for any amount by which the carrying value of goodwill exceeds its fair value.

Impairment

The Company is required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets. The Company tests for impairment on a quarterly basis. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Any impairment charge incurred is expensed and reduces our recorded basis in the asset.

Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and natural gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. See Note 5, Asset Retirement Obligations for more detail.

Stock-based Compensation

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). Accordingly, no compensation expense is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. However, expense is recorded related to restricted stock granted to employees. Compensation expense associated with awards to employees who are eligible for retirement is recognized over the explicit service period of the award. Compensation expense for such awards that are granted subsequent to the adoption of SFAS No. 123R on January 1, 2006, will be fully expensed on the date of grant. If the Company had recognized compensation expense at the time an employee became eligible for retirement and had satisfied all service requirements, non-cash stock based compensation expense would have increased by $1.0 million, $0.3 million, and $0.1 million in 2005, 2004, and 2003, respectively. See Note 12. Employee Benefit Plans for more information.

If compensation expense for the stock based awards had been determined using the provisions of Statement of Financial Accounting Standard No. 123, Accounting for Stock-Based Compensation

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(SFAS 123), the Company s net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

	Year Ended December 31,		
	2005	2004	2003
As Reported:			
Non-cash stock based compensation (net of taxes)	$ 2,483	$ 1,108	$ 381
Net income	103,425	82,147	63,641
Basic net income per share	2.12	1.74	1.41
Diluted net income per share	2.09	1.72	1.40
Pro Forma:			
Non-cash stock based compensation (net of taxes)	3,091	2,289	1,929
Net income	102,817	80,966	62,093
Basic net income per share	2.11	1.72	1.38
Diluted net income per share	2.08	1.70	1.36

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The following amounts represent weighted average values used in the model to calculate the fair value of the options granted during 2005, 2004, and 2003:

	Year Ended December 31,		
	2005	2004	2003
Risk free interest rate	3.7%	3.2%	3.0%
Expected life	6 years	6 years	4 years
Expected volatility	46.0%	34.8%	36.5%
Expected dividend yield	0.00%	0.00%	0.00%

Segment Reporting

The Company has only one operating segment, the development and exploitation of oil and natural gas reserves. Additionally, all of our assets are located in the United States and all of our oil and natural gas revenues are derived from customers located in the United States.

In 2005, 26%, 16%, 14%, and 10% of total oil and natural gas production was sold to Shell, Eighty-Eight Oil, BP, and Chevron, respectively. In 2004, 29% and 27% of total oil and natural gas production was sold to Shell and ConocoPhillips, respectively. In 2003, 28%, 26%, and 11% of total oil and natural gas production was sold to ConocoPhillips, Shell, and Eighty-Eight Oil, respectively.

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Valuation allowances are established when necessary to reduce deferred tax assets to amounts expected to be realized. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

Revenue Recognition

Revenues are recognized for the Company s share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Revenues are also reduced by any

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

processing and other fees paid, except for transportation costs paid to third parties which are recorded as expense. Natural gas revenues are recorded using the sales method of accounting, whereby revenue is recognized as natural gas is sold rather than as produced. Royalties, net profits interests, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, we estimate and record the expected sales volumes and values for those properties. The Company also does not recognize revenue for the production in tanks, purchased oil marketed on behalf of third parties, or oil in pipelines that has not been delivered to the purchaser. The Company s net oil inventories in pipelines were 49,543 Bbls and 44,901 Bbls at December 31, 2005 and 2004, respectively. Natural gas imbalances at December 31, 2005 and December 31, 2004, were 204,400 MMBTU over delivered to the Company and 259,500 MMBTU under delivered to the Company, respectively.

Shipping Costs

Shipping costs in the form of pipeline fees and trucking costs paid to third parties are incurred to transport oil and natural gas production from certain properties to a different market location for ultimate sale. These costs are included in other operating expense in our Consolidated Statements of Operations.

Hedging and Related Activities

We use various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our oil and natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter forward derivative contracts with large financial institutions.

Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) requires us to recognize all of our derivative financial instruments in our consolidated balance sheets as either assets or liabilities and measure them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships must be designated, documented, and reassessed periodically.

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in other comprehensive income in stockholders equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss is recognized into earnings immediately.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income, which includes unrealized gains and losses on derivative financial instruments. The Company chooses to show comprehensive income annually as part of its Consolidated Statement of Stockholders Equity.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Use of Estimates

Preparing financial statements in conformity with accounting principles generally accepted in the United States requires management to make certain estimations and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities in the consolidated financial statements and the reported amounts of revenues and expenses reported. Actual results could differ materially from those estimates.

Estimates made in preparing these consolidated financial statements include the Company s estimated proved oil and natural gas reserve volumes used in calculating depletion, depreciation, and amortization expense; the estimated future cash flows and fair value of our properties used in determining the need for any impairment write-down; and the timing and amount of future abandonment costs used in calculating the Company s asset retirement obligations. See Note 5. Asset Retirement Obligations. Future changes in the assumptions used could have a significant impact on reported results in future periods.

New Accounting Standards

Statement of Financial Accounting Standards No. 123R, Share-Based Payment . In December 2004, the FASB issued Statement No. 123R, Share-Based Payment . SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supersedes APB 25. SFAS No. 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The effective date of SFAS No. 123R is January 1, 2006 for calendar year companies.

SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R, for all share-based payments granted after that date, and for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but it also permits entities to restate financial statements of previous periods based on pro-forma disclosures made in accordance with SFAS No. 123. The Company adopted the requirements of SFAS No. 123R on January 1, 2006 using the modified prospective method.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options when calculating the pro forma effect of applying the fair value provisions of SFAS No. 123 as disclosed above under Stock-based Compensation. While SFAS No. 123R permits entities to continue to use such a model, the standard also permits the use of a lattice model. The Company plans to continue using a Black-Scholes option pricing model to measure the fair value of employee stock options upon the adoption of SFAS No. 123R.

Under SFAS No. 123R, the pro forma disclosures previously permitted under SFAS No. 123 and presented above will no longer be an alternative to financial statement recognition.

SFAS No. 123R also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated because it depends on, among other things, when employees exercise stock options and the Company s stock price at that time.

In 2006, the Company expects to record total compensation expense related to stock options granted prior to January 1, 2006 of approximately $1.3 million. The Company has not yet determined the financial

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

statement impact of adopting SFAS No. 123R for options granted subsequent to December 31, 2005 because they depend on, among other things, the number of options granted in the future and the Company s future stock price.

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations . In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. The Company adopted FIN No. 47 as of December 31, 2005. There was no material impact on the Company s results of operations, financial condition, or cash flows.

Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3 . In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for the Company s fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS No. 154 to have a material impact on the Company s results of operations, financial condition, or cash flows.

Emerging Issues Task Force (EITF) Issue 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty . The Emerging Issues Task Force considered Issue No. 04-13 in its May 17, 2005 and June 16, 2005 meetings to discuss inventory sales to another entity in the same line of business from which it also purchases inventory. The Task Force reached consensus on the issue that purchases and sales of inventory with the same counterparty should be combined as a single nonmonetary transaction (net) and noted factors that may indicate that transactions were entered into in contemplation of one another. The Task Force also concluded that transfers of finished goods inventory in exchange for work-in-progress or raw materials should be recognized at fair value and prescribes additional disclosures. The Task Force ratified Issue No. 04-13 at its September 28, 2005 meeting, which should be applied to new arrangements entered into in the first interim or annual reporting period beginning after March 15, 2006. The Company has previously reported transactions of this nature on a net basis; therefore, the Company does not expect Issue No. 04-13 to have a material impact on the Company s results of operations, financial condition, or cash flows.

3. Acquisitions

2003 Acquisitions

On July 31, 2003, the Company purchased interests in natural gas properties in North Louisiana from a group of private sellers at a cost of $54.6 million. Subsequently, we have purchased several smaller interests in these properties. The original purchase was effective June 1, 2003. Beginning August 1, 2003, revenues and expenses from these properties have been included in the Company s Consolidated Statements of Operations and drilling costs have been included in Development of oil and natural gas properties in the Consolidated Statements of Cash Flows. From June 1, 2003 to July 31, 2003, revenues, expenses, and development capital of the properties were treated as adjustments to the purchase price. The

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properties are located in the Elm Grove Field in Bossier Parish, Louisiana and are non-operated working interests ranging from 1% to 47% across 1,800 net acres in 15 sections.

2004 Acquisitions

Cortez Acquisition. On April 14, 2004, the Company purchased all of the outstanding capital stock of Cortez Oil & Gas, Inc. (Cortez), a privately held, independent oil and natural gas company, for a total purchase price of $127.0 million, which includes cash paid to Cortez former shareholders of $85.8 million, the repayment of $39.4 million of Cortez debt, and transaction costs incurred of $1.8 million.

The acquired oil and natural gas properties are located primarily in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico and in the Mid-Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale north of Fort Worth, Texas. Cortez operating results are included in the Company s Consolidated Statement of Operations beginning in April 2004.

The calculation of the total purchase price and the allocation as of December 31, 2005 to the fair value of net assets acquired at April 14, 2004, are as follows (in thousands):

Calculation of total purchase price:		
Cash paid to Cortez former owners	$	85,805
Cortez debt repaid		39,449
Transaction costs		1,760
Total purchase price	$	127,014
Allocation of purchase price to the fair value of assets acquired:		
Cash	$	3,206
Current assets, excluding cash		5,946
Proved oil and gas properties		120,503
Unproved oil and gas properties		3,011
Goodwill		37,908
Total assets acquired		170,574
Current liabilities		(5,673)
Non-current liabilities		(996)
Deferred income taxes		(36,891)
Total liabilities assumed		(43,560)
Fair value of net assets acquired	$	127,014

The purchase price allocation resulted in $37.9 million of goodwill primarily as the result of the difference between the fair value of acquired oil and natural gas properties and their lower carryover tax basis, which resulted in deferred taxes of $36.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to our existing operations, particularly the additional interest in the CCA and Permian properties acquired through the Cortez acquisition. None of the goodwill is deductible for income tax purposes.

Overton. On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Field assets are in the same core area as our interests in Elm Grove Field and have similar geology. Overton operating results are included in our Consolidated Statement of Operations beginning in July 2004.

2005 Acquisitions

Williston Basin Acquisition. On September 8, 2005, we acquired oil and natural gas properties in the Williston Basin for a purchase price of approximately $28.6 million. Production from the properties, which are concentrated primarily in the Crane Field in Montana and the Tracy Mountain Field in North Dakota, is approximately 94% oil and 77% operated.

Crusader Acquisition. On October 14, 2005, the Company purchased all of the outstanding capital stock of Crusader Energy Corporation (Crusader), a privately held, independent oil and natural gas company, for a purchase price of approximately $109.7 million, which includes cash paid to Crusader s former shareholders of $79.2 million, the repayment of $29.7 million of Crusader s debt, and transaction costs incurred of $0.8 million.

The acquired properties are located primarily in the western Anadarko Basin and the Golden Trend area of Oklahoma. Crusader s operating results are included in the Company s Consolidated Statement of Operations beginning in October 2005.

The calculation of the total purchase price and the estimated allocation as of December 31, 2005 to the fair value of net assets acquired at October 14, 2005, are as follows (in thousands):

Calculation of total purchase price:		
Cash paid to Crusader s former owners	$	79,142
Crusader debt repaid		29,732
Transaction costs		813
Total purchase price	$	109,687
Allocation of purchase price to the fair value of assets acquired:		
Cash	$	18,592
Current assets, excluding cash		3,131
Proved oil and gas properties		85,388
Unproved oil and gas properties		6,863
Goodwill		21,138
Total assets acquired		135,112
Current liabilities		(8,688)
Non-current liabilities		(1,190)
Deferred income taxes		(15,547)
Total liabilities assumed		(25,425)
Fair value of net assets acquired	$	109,687

The purchase price allocation resulted in $21.1 million of goodwill primarily as the result of the difference between the fair value of acquired oil and natural gas properties and their lower carryover tax basis, which resulted in deferred taxes of $15.5 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to our existing operations. None of the goodwill is deductible for income tax purposes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Kerr-McGee Acquisition. On November 30, 2005, we acquired oil and natural gas properties from Kerr-McGee Corporation for a purchase price of approximately $101.4 million. The acquired properties are located in the Levelland-Slaughter, Howard Glasscock, Nolley-McFarland and Hutex fields in West Texas and the Oakdale, Calumet and Rush Springs fields in western Oklahoma. The operating results for these properties are included in our Consolidated Statement of Operations beginning in December 2005.

4. Commitments and Contingencies

Leases

We lease office space and equipment that have remaining non-cancelable lease terms in excess of one year. The following table summarizes by year our remaining non-cancelable future payments under operating leases as of December 31, 2005 (in thousands):

2006	$	1,918
2007		1,498
2008		1,509
2009		1,393
2010		1,362
Thereafter		4,036

Our operating lease rental expense was approximately $3.1 million, $3.5 million, and $1.5 million in 2005, 2004, and 2003, respectively.

5. Asset Retirement Obligations

In August 2001, the FASB issued SFAS 143, which the Company adopted as of January 1, 2003. This statement requires us to record a liability in the period in which an asset retirement obligation (ARO) is incurred. Also, upon initial recognition of the liability, we must capitalize additional asset cost equal to the amount of the liability. In addition to any obligations that arise after the effective date of SFAS 143, upon initial adoption we must recognize (1) a liability for any existing AROs, (2) capitalized cost related to the liability, and (3) accumulated depletion, depreciation, and amortization on that capitalized cost.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect of accounting change adjustment to record (1) a $4.0 million increase in the carrying values of proved properties; (2) a $2.1 million decrease in accumulated depletion, depreciation, and amortization; (3) a $5.2 million increase in other non-current liabilities; and (4) a gain of $0.9 million, net of tax, as a cumulative effect of accounting change on January 1, 2003. The Company does not include a market risk premium in its risk estimates as the effect would not be material.

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on our oil and natural gas properties and related facilities disposal. As of December 31, 2005, the Company had $4.0 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on our Bell Creek property. This amount is

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ENCORE ACQUISITION COMPANY
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included in Other assets in the accompanying Consolidated Balance Sheet. The following table summarizes the changes in the Company s future abandonment liability recorded in Future abandonment cost on the Company s Consolidated Balance Sheet for the period from January 1, 2004 through December 31, 2005 (in thousands):

	December 31,	
	2005	2004
Future abandonment liability at January 1	$ 6,601	$ 5,341
Acquisition of properties	2,221	1,165
Wells drilled	990	467
Accretion expense	515	317
Plugging and abandonment costs incurred	(745)	(280)
Revision of estimates	4,848	(409)
Future abandonment liability at December 31	$ 14,430	$ 6,601

During 2005, the Company increased its discounted estimate of future plugging liability by $4.8 million as actual plugging costs experienced during 2005 increased due to plugging cost escalations (which outpaced inflation), increases in the cost of outside services, and changes in various state regulations.

6. Capitalization of Exploratory Well Costs

The Company adopted FASB Staff Position (FSP) 19-1 Accounting for Suspended Well Costs on July 1, 2005. FSP 19-1 amends SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, to permit the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Upon the adoption of FSP 19-1, the Company evaluated all existing capitalized exploratory well costs and determined that there was no impact on the Company s results of operations, financial condition, or cash flows. The Company began its exploratory drilling program in the second quarter of 2004, with wells drilled located primarily in the shallow gas zones of our acreage in north central Montana. The following table reflects the net changes in capitalized exploratory well costs during 2005, 2004, and 2003 (in thousands), and does not include amounts that were capitalized and subsequently expensed in the same period.

	2005	2004	2003
Beginning balance at January 1	$ 3,242	$	$
Additions to capitalized exploratory well costs pending the determination of proved reserves	48,208	27,723	
	(42,644)	(24,481)	

Reclassification to proved property and equipment based on the determination of proved reserves						
Capitalized exploratory well costs charged to expense		(2,246)				
Total	$	6,560	$	3,242	$	

All of the capitalized exploratory well costs at December 31, 2005 related to wells in progress or wells for which drilling had been completed for less than one year.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Accounts Payable and Accrued Liabilities

Other current liabilities were as follows at December 31 (in thousands):

	2005	2004
Oil and natural gas revenues payable	$ 4,544	$ 2,413
Net profits payable	1,634	558
Interest	12,531	2,630
Other	9,592	5,280
Total	$ 28,301	$ 10,881

8. Long-Term Debt

The following table details the Company s long-term debt at December 31 (in thousands):

	2005	2004
Revolving credit facility	$ 80,000	$ 79,000
$8^3/8$% Notes		150,000
$6^1/4$% Notes	150,000	150,000
6% Notes, net of unamortized discount of $5,317	294,683	
$7^1/4$% Notes, net of unamortized discount of $1,494	148,506	
Total	$ 673,189	$ 379,000

Senior Subordinated Notes

$8^3/8$% Senior Subordinated Notes. On June 25, 2002, the Company sold $150.0 million of $8^3/8$% senior subordinated notes maturing on June 15, 2012 (the $8^3/8$% Notes). The $8^3/8$% Notes were redeemed in August 2005 at a cost of $165.9 million using proceeds received from the issuance of the Company s 6% senior subordinated notes on July 13, 2005. The redemption price included an early payment premium of $15.9 million. Combined with the unamortized balance of the related debt issuance costs, the Company incurred a loss on early redemption of debt of $19.5 million, which the Company recognized in earnings for the year ended December 31, 2005.

$6^1/4$% Senior Subordinated Notes. On April 2, 2004, the Company issued $150.0 million of $6^1/4$% senior subordinated notes due April 15, 2014 (the $6^1/4$% Notes). The Company received net proceeds of approximately $146.4 million after paying all costs associated with the offering. The net proceeds were used to fund the acquisition of Cortez Oil & Gas, Inc. and repay amounts outstanding under the revolving credit facility. Interest on the $6^1/4$% Notes is paid semi-annually on April 15 and October 15.

6% Senior Subordinated Notes. On July 13, 2005, the Company issued $300.0 million of its 6% senior subordinated notes due July 15, 2015 (the 6% Notes). The Company received net proceeds of approximately $294.5 million from the private placement and used approximately $165.9 million of the net proceeds to redeem all of the outstanding $8^3/8$% Notes. The remaining net proceeds from the issuance were used to reduce the balance outstanding under the Company s revolving credit facility. The 6% Notes require semi-annual interest payments on January 15 and July 15.

7^{1}/4% Senior Subordinated Notes. On November 23, 2005, the Company issued $150.0 million of its 7^{1}/4% senior subordinated notes due December 1, 2017 (the 7^{1}/4% Notes and together with the ^{3}/8% Notes, the 6^{1}/4% Notes, and the 6% Notes, the Notes). The Company received net proceeds of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approximately $148.5 million and used the proceeds to reduce the balance outstanding under the Company s revolving credit facility. The $7^1/4$% Notes require semi-annual interest payments on June 1 and December 1 of each year.

All of the Company s subsidiaries are currently subsidiary guarantors of the Notes. Since (1) each subsidiary guarantor is 100% owned by the Company, (2) the Company has no assets or operations that are independent of its subsidiaries, (3) the subsidiary guarantees are full and unconditional and joint and several and (4) all of the Company s subsidiaries are subsidiary guarantors, the Company has not included the financial statements of each subsidiary in this report. The subsidiary guarantors may without restriction transfer funds to the Company in the form of cash dividends, loans and advances.

The indentures governing the Notes contain certain affirmative, negative, and financial covenants, which include limitations on incurrence of additional debt, restrictions on asset dispositions and restricted payments, maintenance of a 1.0 to 1.0 current ratio, and maintenance of EBITDA, as defined, to interest expense ratio of 2.5 to 1.0. As of December 31, 2005, the Company was in compliance with all covenants of the Notes.

Revolving Credit Facility

On August 19, 2004, the Company entered into an amended and restated five-year senior secured revolving credit facility with a bank syndicate comprised of Bank of America, N.A. and other lenders. Availability under the amended and restated credit facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The initial borrowing base is $400.0 million and may be increased to up to $750.0 million. At various times in 2005, the Company amended the credit facility to change the borrowing base, allow additional permitted subordinated debt, change the definition of EBITDA to add back exploration expense (EBITDAX), increase the availability of letters of credit from 15% of the borrowing base to 20%, and extend the original maturity date of the credit facility. The borrowing base as of December 31, 2005 was $550.0 million. The amended and restated credit facility matures on December 29, 2010.

The Company s obligations under the amended and restated credit facility are guaranteed by its restricted subsidiaries and secured by a first priority-lien on substantially all of its proved oil and natural gas reserves and a pledge of the capital stock and equity interests of the Company s restricted subsidiaries.

Amounts outstanding under the amended and restated credit facility are subject to varying rates of interest based on (1) the amount outstanding under the amended and restated credit facility in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. The following table summarizes the calculation of the various interest rates for both Eurodollar and base rate loans:

Ratio of Total Outstanding to Borrowing Base	Eurodollar Loans(a)	Base Rate Loans(b)
Less than .40 to 1	LIBOR + 1.000%	Base Rate + 0.000%
From .40 to 1 but less than .75 to 1	LIBOR + 1.250%	Base Rate + 0.000%
From .75 to 1 but less than .90 to 1	LIBOR + 1.500%	Base Rate + 0.250%
.90 to 1 or greater	LIBOR + 1.750%	Base Rate + 0.500%

(a) The LIBOR rate is equal to the rate determined by Bank of America, N.A. to be the British Bankers Association Interest Settlement Rate for deposits in dollars for a similar interest period (either one, two, three or six months, or such other period as selected by Encore, subject to availability at each lender).

(b) The Base Rate is calculated as the highest of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5%.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The borrowing base will be redetermined each April 1 and October 1, commencing April 1, 2006. The bank syndicate has the ability to request one additional borrowing base redetermination per year, and the Company is permitted to request two additional borrowing base redeterminations per year. Generally, if amounts outstanding ever exceed the borrowing base, the Company must reduce the amounts outstanding to the redetermined borrowing base within six months, provided that if amounts outstanding exceed the borrowing base as a result of any sale of the Company s assets or permitted subordinated debt, the Company must reduce the amounts outstanding immediately upon consummation of the sale.

Borrowings under the amended and restated credit facility may be repaid from time to time without penalty.

The amended and restated credit facility contains certain affirmative, negative, and financial covenants; which include, but not limited to, (1) limitations on the incurrence of additional debt, payment of dividends, repurchases of the Company s common stock, asset dispositions and restricted payments, (2) maintenance of a 1.0 to 1.0 current ratio, and (3) maintenance of EBITDAX, as defined, to interest expense ratio of 2.5 to 1.0. As of December 31, 2005, the Company was in compliance with all covenants in the amended and restated credit facility.

The Company incurs a commitment fee on the unused portion of the facility determined based on the ratio of borrowings to the borrowing base in effect on such date. The following table summarizes the calculation of the Company s commitment fee:

Borrowings to Borrowing Base	Commitment Fee Percentage
<.40 to 1	0.250%
>.40 to 1< .90 to 1	0.375%
>.90 to 1	0.500%

During 2005 and 2004, the weighted average interest rates for our revolving credit facilities were 6.5% and 6.6%, respectively.

Letters of Credit

The Company had $50.0 million and $30.4 million of outstanding letters of credit at December 31, 2005 and 2004, respectively. These letters of credit are posted primarily with two counterparties to the Company s commodity derivative contracts and are used in lieu of cash margin deposits with those counterparties.

Long-Term Debt Maturities

The following table illustrates the Company s long-term debt maturities at December 31, 2005 (in thousands):

		Payments Due by Period			
	Total	2006	2007-2008	2009-2010	Thereafter
$6^1/4$% Notes	$ 150,000	$	$	$	$ 150,000
6% Notes	300,000				300,000
$7^1/4$% Notes	150,000				150,000
Revolving credit facility	80,000			80,000	
Total	$ 680,000	$	$	$ 80,000	$ 600,000

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Consolidated cash payments for interest were $24.2 million, $21.4 million, and $16.2 million, respectively, for 2005, 2004, and 2003.

During 2005 and 2004, the weighted average interest rate for total indebtedness, including our senior subordinated notes, revolving credit facility, letters of credit, and related miscellaneous fees was 6.8% and 7.7%, respectively.

9. Taxes

Income Taxes

The components of the Company s total income tax expense including amounts related to items shown net of income taxes on the Consolidated Statements of Operations were attributed to the following items (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Taxes related to:			
Income before cumulative effect of accounting change	$ 53,948	$ 40,492	$ 36,102
Cumulative effect of accounting change			529
Total tax expense	$ 53,948	$ 40,492	$ 36,631

The components of the income tax provision related to income/loss before cumulative effect of accounting change and extraordinary loss are as follows (in thousands):

	Year Ended December 31,		
	2005	2004	? 2003
Federal:			
Current	$ (2,084)	$ 1,788	$ 991
Deferred	53,147	35,470	32,145
Total federal	51,063	37,258	33,136
State (net of federal benefit):			
Current		125	
Deferred	2,885	3,109	2,966
Total state	2,885	3,234	2,966
Income tax provision	$ 53,948	$ 40,492	$ 36,102

Reconciliation of income tax expense with tax at the Federal statutory rate is as follows (in thousands):

Year Ended December 31,

	2005	2004	2003
Income before income taxes	$ 157,373	$ 122,639	$ 98,880
Tax at statutory rate	$ 55,081	$ 42,923	$ 34,608
State income taxes, net of federal benefit	2,885	3,234	2,966
Section 29 and 43 credits	(3,227)	(3,816)	(1,322)
Permanent differences and other	(791)	(1,849)	(150)
Income tax provision	$ 53,948	$ 40,492	$ 36,102

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The major components of the net current deferred tax asset and net long-term deferred tax liability are as follows at December 31 (in thousands):

	December 31,	
	2005	2004
Current:		
Assets:		
Unrealized hedge loss in other comprehensive income	$ 26,427	$ 10,550
Derivative fair value loss hedges	2,603	568
Total current deferred tax assets	$ 29,030	$ 11,118
Long-term:		
Assets:		
Alternative minimum tax	$ 2,073	$ 2,017
Unrealized hedge loss in other comprehensive income	16,964	11,522
Derivative fair value loss hedges	1,424	215
Section 43 credits	13,227	6,350
Other	3,004	1,289
Total long-term deferred tax assets	36,692	21,393
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(249,960)	(167,457)
Net long-term deferred tax liability	$ (213,268)	$ (146,064)

Cash income tax payments in the amount of $0.2 million, $3.7 million, and $1.5 million were made in 2005, 2004, and 2003, respectively. If unused, $2.0 million of the Section 43 credits will expire in 2023, $6.1 million in 2024, and $5.1 million in 2025. Additionally, the Company recognized in equity a benefit resulting from the reduction in income taxes payable related to the exercise of employee stock options and the vesting of restricted stock in the amount of $1.4 million, $1.4 million, and $0.1 million in the years ended December 31, 2005, 2004, and 2003, respectively.

Taxes Other than Income Taxes

Taxes other than income taxes were comprised of the following (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Production and severance taxes	41,195	27,491	19,999
Property and ad valorem taxes	4,406	2,822	2,014
Franchise, payroll, and other taxes	1,246	868	677

Total	$ 46,847	$ 31,181	$ 22,690

10. Stockholders Equity

Public Offerings of Common Stock

On November 13, 2003, the Company priced a public offering of 12.0 million shares of the Company s common stock at a price to the public of $13.50 per share. The underwriters also exercised their over-allotment option for an additional 1.59 million shares of common stock, at a price of $13.50 per

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share, on December 2, 2003, for a total of 13.59 million shares. The Company used all of the net proceeds to repurchase 10,299,964 shares of the Company s common stock from J.P. Morgan Partners (SBIC), LLC and 3,290,036 shares from Warburg Pincus Equity Partners L.P. at a price of $12.9183 per share. The 13.59 million shares the Company purchased were retired upon repurchase. The Company s total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering.

On June 8, 2004, we priced a public offering of 3.0 million shares of our common stock at a price to the public of $17.97 per share. The net proceeds of the offering, after underwriting discounts and commissions, and other related expenses were approximately $52.9 million. The Company used the net proceeds of this offering to repay indebtedness under its revolving credit facility and for general corporate purposes.

Shelf Registration on Form S-3

On June 30, 2004, the Company filed a shelf registration with the SEC on Form S-3 (Registration No. 333-117036). Using this process, we may offer common stock, preferred stock, senior debt and subordinated debt in one or more offerings with a total initial offering price of up to $500.0 million. On November 23, 2005, the Company issued $150.0 million of $7^1/4$% senior subordinated notes under the shelf registration statement, which lowered the amount available for future offerings to $350.0 million.

Stock Split

On June 15, 2005, the Company announced that its Board of Directors approved a three-for-two split of the Company s outstanding common stock in the form of a stock dividend. The dividend was distributed on July 12, 2005, to stockholders of record at the close of business on June 27, 2005 (the Record Date). In lieu of issuing fractional shares, the Company paid cash for such fractional shares based on the closing price of the common stock on the Record Date.

The effect of the stock split on the December 31, 2004 balance sheet is to reduce additional paid-in capital by $0.2 million and increase common stock by $0.2 million. The balances of additional paid-in capital and common stock at December 31, 2004 have been adjusted accordingly and all share and per-share information included in the accompanying consolidated financial statements and related notes thereto for all periods presented have been adjusted to retroactively reflect the stock split.

Common Stock Option Exercises

During the years ended December 31, 2005, 2004 and 2003, employees of the Company exercised 137,413, 303,865 and 218,591 options, respectively. The Company received proceeds from the option exercises of $1.5 million, $2.8 million, and $2.0 million in the years ended December 31, 2005, 2004, and 2003, respectively, related to these option exercises.

Preferred Stock

The Company s authorized capital stock includes 5,000,000 shares of preferred stock, none of which are issued and outstanding. The Board of Directors has not determined the rights and privileges of holders of such preferred stock, and we have no current plans to issue any shares of preferred stock.

11. Earnings Per Share (EPS)

Under Statement of Financial Accounting Standards No. 128, the Company must report basic EPS, which excludes the effect of potentially dilutive securities, and diluted EPS, which includes the effect of

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

all potentially dilutive securities. EPS for the periods presented is based on weighted average common shares outstanding for the period.

The following table reflects EPS data for the years ended December 31 (in thousands, except per share data):

	Year Ended December 31,		
	2005	2004	2003
Numerator:			
Income before cumulative effect of accounting change	$ 103,425	$ 82,147	$ 62,778
Cumulative effect of accounting change			863
Net income	$ 103,425	$ 82,147	$ 63,641
Denominator:			
Denominator for basic earnings per share Weighted average shares outstanding	48,682	47,090	45,153
Effect of dilutive options and diluted restricted stock	840	648	347
Denominator for diluted earnings per share	49,522	47,738	45,500
Basic income per common share before accounting change	$ 2.12	$ 1.74	$ 1.39
Cumulative effect of accounting change, net of tax			0.02
Basic income per common share after accounting change	$ 2.12	$ 1.74	$ 1.41
Diluted income per common share before accounting change	$ 2.09	$ 1.72	$ 1.38
Cumulative effect of accounting change, net of tax			0.02
Diluted income per common share after accounting change	$ 2.09	$ 1.72	$ 1.40

(a) There were no antidilutive options or antidilutive restricted stock outstanding for the years ended December 31, 2005, 2004, and 2003.

12. Employee Benefit Plans

401(k) plan

We make contributions to the Encore Acquisition Company 401(k) Plan, which is a voluntary and contributory plan for eligible employees. Our contributions, which are based on a percentage of matching employee contributions, totaled $0.8 million in 2005, $0.6 million in 2004, and $0.5 million in 2003. The Company s 401(k) plan does not currently allow employees to invest in securities of the Company.

Incentive Stock Plans

During 2000, the Company s Board of Directors and stockholders approved the 2000 Incentive Stock Plan (the Plan). The original plan was amended and restated effective March 18, 2004. The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved for issuance pursuant to the Plan is 4,500,000. As of December 31, 2005, there were 1,656,960 shares remaining under the Plan. The Plan provides for the granting of cash awards,

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Company s Board of Directors.

The Plan contains the following individual limits:

an employee may not be awarded more than 150,000 shares of common stock in any calendar year;

a nonemployee director may not be awarded more than 10,000 shares of common stock in any calendar year; and

an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1.0 million.

All options that have been granted under the Plan have a strike price equal to the market price on the date of grant. Additionally, all have a ten-year life and vest equally over a two or three-year period. The following table summarizes the changes in the number of outstanding options and their related weighted average strike prices during 2005, 2004, and 2003:

	Year Ended December 31, 2005		Year Ended December 31, 2004		Year Ended December 31, 2003	
	Number of Options	**Weighted Average Strike Price**	**Number of Options**	**Weighted Average Strike Price**	**Number of Options**	**Weighted Average Strike Price**
Outstanding at beginning of year	1,520,586	$ 12.00	1,444,431	$ 9.91	1,767,767	$ 9.75
Granted(a)	115,255	26.55	389,784	17.42	74,688	12.97
Forfeited	(57,616)	17.94	(9,764)	10.49	(179,433)	10.74
Exercised	(137,413)	9.07	(303,865)	9.07	(218,591)	8.95
Outstanding at end of year	1,440,812	13.20	1,520,586	12.00	1,444,431	9.91
Exercisable at end of year	1,089,677	11.04	948,771	9.77	872,415	9.30

(a) During 2005, 2004, and 2003, there were zero, 37,500, and 22,500 stock options, respectively, granted to non-employee directors. The weighted average fair value of individual options granted in 2005, 2004, and 2003 was $12.99, $6.87, and $4.25, respectively.

Additional information about common stock options outstanding and exercisable at December 31, 2005 is as follows:

Range of Strike	Number of Options	Weighted Average Life	Weighted Average Strike	Number of Options

Year of Grant	Prices Per Share	Outstanding	(Years)	Price	Exercisable
2001	$ 8.40 to $ 9.33	542,474	5.5	$ 8.92	542,474
2002	$ 8.50 to $12.40	380,587	6.7	11.72	380,587
2003	$11.49 to $13.61	51,258	7.6	12.68	36,684
2004	$17.17 to $19.77	363,224	8.1	17.44	129,932
2005	$26.55	103,269	9.1	26.55	
		1,440,812	6.8	13.20	1,089,677

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the years ended December 31, 2005, 2004, and 2003, we issued 130,854, 102,106, and 68,191 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2005:

	Year of Vesting					
Year of Grant	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
2002	52,694	52,693				105,387
2003	19,569	19,522	19,522			58,613
2004	28,462	33,362	4,899	4,898		71,621
2005	5,511	5,511	42,367	36,793	36,793	126,975
Total	106,236	111,088	66,788	41,691	36,793	362,596

During the years ended December 31, 2005, 2004, and 2003, we issued 155,190, 86,537, and zero shares of restricted stock to employees that not only depend on the passage of time and continued employment, but on certain performance measures, for their vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2005:

	Year of Vesting					
Year of Grant	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
2004		25,832	25,828	25,828		77,488
2005			47,730	47,730	47,730	143,190
Total		25,832	73,558	73,558	47,730	220,678

Total deferred compensation of $9.0 million was outstanding and included in Deferred Compensation in the accompanying Consolidated Balance Sheet as of December 31, 2005. Estimated amortization of deferred compensation is shown in the table below (in thousands):

Year Ended December 31,	**Estimated Amortization Expense**
2006	$ 3,835
2007	2,918
2008	1,567
2009	617
2010	70
Total	$ 9,007

Subsequent to December 31, 2005, we issued 389,922 shares of restricted stock to our employees as part of our annual incentive program.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Financial Instruments

The following table sets forth the book value and estimated fair value of the Company s financial instruments as of the dates indicated (in thousands):

	December 31, 2005		December 31, 2004	
	Book Value	Fair Value	Book Value	Fair Value
Cash and cash equivalents	$ 1,654	$ 1,654	$ 1,103	$ 1,103
Accounts receivable, net	76,960	76,960	43,839	43,839
Accounts payable	(27,281)	(27,281)	(24,375)	(24,375)
$8^3/8$% Notes			(150,000)	(166,500)
$6^1/4$% Notes	(150,000)	(145,500)	(150,000)	(148,500)
6% Notes	(294,683)	(279,000)		
$7^1/4$% Notes	(148,506)	(150,000)		
Revolving credit facility	(80,000)	(80,000)	(79,000)	(79,000)
Commodity derivative contracts	(86,794)	(86,794)	(52,394)	(52,394)
Deferred premiums on derivative contracts	(30,141)	(30,141)		
Interest rate swaps			462	462
Plugging bond	690	843	625	737

The book value of cash and cash equivalents approximates fair value because of the short maturity of these instruments. The fair values of our senior subordinated notes were determined using their open market quote as of December 31, 2005. The difference between book value and fair value represents the premium or discount on that date. The book value of the revolving credit facility approximates the fair value as the interest rate is variable. The plugging bond is classified as held to maturity and therefore is recorded at amortized cost, which at December 31, 2005 is less than fair value. Commodity contracts and interest rate swaps are marked-to-market each quarter in accordance with the provisions of SFAS 133.

Commodity Derivatives

The Company hedges commodity price risk with swap contracts, put contracts, and collar contracts and hedges interest rate risk with swap contracts. Swap contracts provide a fixed price for a notional amount of volume. Put contracts provide a fixed floor price on a notional amount of volume while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide a floor price for a notional amount of volume while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, we occasionally sell put contracts with a strike price well below the floor price of the collar. These short put contracts do not qualify for hedge accounting under SFAS 133, and accordingly, the mark-to-market change in the value of these contracts is recorded as fair value gain/loss in the Consolidated Statement of Operations.

In order to more effectively hedge the cash flows received on our oil and natural gas production, the Company enters into financial instruments, commonly called basis swaps, whereby we swap certain per Bbl or per Mcf floating market indices for a fixed amount. These market indices are a component of the price the Company is paid on its actual production and by fixing this component of our marketing price, we are able to realize a net price with a more consistent differential to NYMEX. Since NYMEX is the basis of all our derivative oil hedging contracts and some of our natural gas contracts, a more consistent differential results in more effective hedges. However, management has elected not to use hedge accounting for certain of these contracts. Instead, we mark these contracts to market each quarter through Derivative fair value (gain) loss in the Consolidated Statements of Operations. Thus, as these contracts do not change the Company s overall hedged volumes, average prices presented in the table below are exclusive of any

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effect of these non-hedge instruments. As of December 31, 2005, the mark-to-market value of these contracts was a $2.4 million asset.

The following tables summarize our open commodity derivative positions designated as cash flow hedges as of December 31, 2005:

Oil Hedges at December 31, 2005

Period	Daily Floor Volume (Bbl)	Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Swap Price (per Bbl)	Fair Market Value (In thousands)
Jan. June 2006	13,500	$ 44.07	1,000	$ 29.88	3,000	$ 37.27	$ (17,899)
July Dec. 2006	13,000	45.00	1,000	29.88	3,000	37.27	(16,081)
Jan. Dec. 2007	8,000	53.75			3,000	36.75	(13,807)
Jan. June 2008					1,000	58.59	(685)

Natural Gas Hedges at December 31, 2005

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (In thousands)
Jan. - Dec. 2006	32,500	$ 6.17	5,000	$ 5.68	12,500	$ 5.08	$ (28,463)
Jan. - Dec. 2007	22,500	6.96			10,000	4.99	(12,278)

As a result of all of our hedging transactions for oil and natural gas, we recognized a pre-tax reduction in revenues of approximately $59.3 million, $38.0 million, and $15.3 million, in 2005, 2004, and 2003, respectively. Based on the fair value of our hedges at December 31, 2005, our unrealized pre-tax loss recorded in Other comprehensive income related to outstanding hedges was $70.5 million for oil and $45.8 million for natural gas. Of the total deferred hedge loss at December 31, 2005 related to commodity contracts, $70.8 million, $44.8 million, and $0.7 million relate to 2006, 2007, and 2008 contracts, respectively.

The Company had $30.1 million of derivative premiums payable recorded at December 31, 2005, of which $22.5 million is considered long-term and is recorded in Deferred premiums on derivatives contracts in the Company s Consolidated Balance Sheet. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from January 2006 to December 2007.

The actual gains or losses we realize from our derivative transactions may vary significantly from the deferred loss amount recorded in equity at December 31, 2005 due to the fluctuation of prices in the commodities markets.

Interest Rate Derivatives

The Company recognized in interest expense a pre-tax loss of approximately $0.1 million, $0.5 million, and $1.9 million in 2005, 2004, and 2003, respectively, related to LIBOR for fixed interest rate swaps that were previously entered into in conjunction with a revolving credit facility that was terminated in 2002. Additionally, $0.1 million and $0.3 million was recognized in Derivative fair value (gain) loss in 2005 and 2004, respectively, for settlements and changes in the swaps fair value, as they no longer qualified for hedge accounting. The final contract expired in June 2005.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Counterparty Risk

The Company s counterparties to hedging contracts include: BNP Paribas; Calyon; Deutsche Bank; Mitsui & Co.; Morgan Stanley; Shell Trading; Wachovia; J. Aron & Company, BP Products, Bank of America, and Koch Supply and Trading. At December 31, 2005, the Company s hedged oil and natural gas production was committed to the counterparties as follows:

Counterparty	Percentage of Hedged Oil Production Committed	Percentage of Hedged Natural Gas Production Committed
BNP Paribas		45%
Calyon	14%	20%
Deutsche Bank	37%	3%
J. Aron & Company	3%	23%
Morgan Stanley	11%	
Wachovia	23%	

Performance on all contracts with J. Aron & Company are guaranteed by its parent, Goldman Sachs & Co. The Company feels the credit-worthiness of the current counterparties is sound and the Company does not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

In order to mitigate the credit risk of financial instruments, the Company enters into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and the Company. Instead of treating separately each financial transaction between our counterparty and the Company, the master netting agreement enables Encore s counterparty and the Company to aggregate all financial trades and treat them as a single agreement. This arrangement benefits the Company in three ways. First, the netting of the value of all trades reduces the requirements of daily collateral posting by Encore. Second, default by counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

14. Related Party Transactions

The Company paid $1.0 million and $0.3 million to affiliates of Hanover Compressor Company in 2005 and 2004, respectively, for field compression services. Mr. I. Jon Brumley, the Company s Chairman, also serves as a director of Hanover Compressor Company.

15. Capitalized Costs and Costs Incurred Relating to Oil and Natural Gas Producing Activities

The capitalized cost of oil and natural gas properties at December 31, 2005 and 2004 are as follows (in thousands):

	December 31, 2005	December 31, 2004
Properties and equipment, at cost successful efforts method:		
Proved properties	$ 1,691,175	$ 1,134,220
Unproved properties	37,646	29,740

Accumulated depletion, depreciation, and amortization	(255,564)	(171,691)
	$ 1,473,257	$ 992,269

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes costs incurred related to oil and natural gas properties:

	Year Ended December 31,		
	2005	2004	2003
	(In thousands)		
Acquisitions			
Proved properties	$ 224,469	$ 204,907	$ 54,484
Unproved properties	21,205	33,926	117
Asset retirement obligations(1)	2,221	1,165	337
Total acquisitions	247,895	239,998	54,938
Development			
Drilling and exploitation	268,520	157,092	98,977
Asset retirement obligations(1)	954	467	83
Total development	269,474	157,559	99,060
Exploration			
Drilling and exploitation	53,316	29,363	
Geological and seismic	3,095	979	
Delay rentals	635	204	
Total exploration	57,046	30,546	
Total costs incurred	$ 574,415	$ 428,103	$ 153,998

(1) The Company adopted SFAS 143 on January 1, 2003 which requires us to capitalize additional asset cost equal to the amount of our discounted asset retirement obligation assumed in a property purchase or incurred in the drilling of new wells.

SUPPLEMENTAL INFORMATION (unaudited)

16. Oil & Natural Gas Producing Activities (unaudited)

The estimates of the Company s proved oil and natural gas reserves, which are located entirely within the United States, were prepared in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board. Proved oil and natural gas reserve quantities are based on estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. There can be no assurance that the proved reserves will be developed within the periods assumed or that prices and costs will remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with Securities and Exchange Commission s guidelines, the Company s estimates of future net cash flows from the properties and the representative value thereof are made using oil and natural gas prices in effect as of the dates of such estimates and are held constant throughout the life of the

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

properties. Year-end prices used in estimating net cash flows at December 31, 2005, 2004, and 2003 were as follows:

	2005	2004	2003
Oil (per Bbl)	$ 61.04	$ 43.46	$ 32.55
Natural gas (per Mcf)	9.44	6.19	5.83

The net profits interest on our Cedar Creek Anticline properties has been deducted from future cash inflows in the calculation of Standardized Measure. The Company s reserve and production quantities from our Cedar Creek Anticline properties have been reduced by the amounts attributable to the net profits interest. In addition, net future cash inflows have not been adjusted for hedge positions outstanding at the end of the year. The future cash flows are reduced by estimated production costs and development costs, which are based on year-end economic conditions and held constant throughout the life of the properties, and by the estimated effect of future income taxes. Future income taxes are based on statutory income tax rates in effect at year end, the Company s tax basis in its proved oil and natural gas properties, and the effect of net operating loss, alternative minimum tax and Section 43 credits, and other carry forwards.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and estimates of other engineers might differ materially from those included in this Annual Report on Form 10-K. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately recovered. Reserve estimates are integral to management s analysis of impairments of oil and natural gas properties and the calculation of depletion, depreciation, and amortization on these properties.

Estimated net quantities of proved oil and natural gas reserves of the Company were as follows as of the dates indicated:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
December 31, 2005			
Proved reserves	148,387	283,865	195,698
Proved developed reserves	101,505	229,950	139,830
December 31, 2004			
Proved reserves	134,048	234,030	173,053
Proved developed reserves	97,114	156,919	123,267
December 31, 2003			
Proved reserves	117,732	138,950	140,890
Proved developed reserves	92,377	104,767	109,838

Encore is committed to sell at least 2,500 barrels of oil per day at a floating market price through 2009.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The changes in proved reserves for the years ended December 31, 2005, 2004, and 2003 were as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2002	111,674	99,818	128,310
Acquisitions of minerals-in-place	13	37,464	6,257
Extensions and discoveries	3,957	7,354	5,182
Improved recovery	12,773	(178)	12,744
Revisions of estimates	(4,084)	3,543	(3,493)
Production	(6,601)	(9,051)	(8,110)
Balance, December 31, 2003	117,732	138,950	140,890
Acquisitions of minerals-in-place	7,853	86,314	22,239
Extensions and discoveries	4,226	27,248	8,768
Improved recovery	11,826	(80)	11,812
Revisions of estimates	(910)	(4,313)	(1,629)
Production	(6,679)	(14,089)	(9,027)
Balance, December 31, 2004	134,048	234,030	173,053
Acquisitions of minerals-in-place	8,333	38,781	14,796
Extensions and discoveries	2,780	28,073	7,459
Improved recovery	11,510	1,132	11,699
Revisions of estimates	(1,413)	2,908	(928)
Production	(6,871)	(21,059)	(10,381)
Balance, December 31, 2005	148,387	283,865	195,698

The Standardized Measure of discounted estimated future net cash flows and changes therein related to proved oil and natural gas reserves (in thousands) is as follows as of the dates indicated:

	December 31, 2005	December 31, 2004	December 31, 2003
Net future cash flows	$ 10,414,091	$ 6,651,858	$ 4,245,574
Future production costs	(3,690,974)	(2,389,359)	(1,683,810)
Future development costs	(250,554)	(194,746)	(75,811)
Future abandonment costs	(121,553)	(49,859)	(43,641)
Future income tax expense	(1,934,504)	(1,221,933)	(716,869)
Future net cash flows	4,416,506	2,795,961	1,725,443
10% annual discount	(2,498,035)	(1,630,342)	(988,504)
	$ 1,918,471	$ 1,165,619	$ 736,939

Standardized measure of discounted estimated future net cash flows

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Primary changes in the Standardized Measure of discounted estimated future net cash flows (in thousands) are as follows for the periods indicated:

	Year Ended December 31,		
	2005	2004	2003
Standardized measure, beginning of year	$ 1,165,619	$ 736,939	$ 624,718
Net change in sales price and production costs	531,793	430,310	81,964
Acquisitions of mineral-in-place	256,257	242,855	91,654
Extensions, discoveries, and improved recovery	229,929	150,112	103,780
Revisions of quantity estimates	(15,455)	(15,217)	(25,650)
Sales, net of production costs	(357,028)	(222,995)	(151,955)
Development costs incurred during the year	268,520	157,092	98,977
Accretion of discount	116,562	73,694	86,511
Change in estimated future development costs	(199,158)	(276,027)	(116,859)
Net change in income taxes	(247,937)	(145,042)	(52,992)
Change in timing and other	169,369	33,898	(3,209)
Standardized measure, end of year	$ 1,918,471	$ 1,165,619	$ 736,939

17. Selected Quarterly Financial Data (unaudited)

The following table sets forth selected quarterly financial data for the years ended December 31, 2005 and 2004:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2005				
Revenues	$ 91,581	$ 99,717	$ 127,572	$ 138,454
Operating income	39,917	43,401	38,911	68,160
Net income	21,784	23,668	20,854	37,119
Basic income per common share	0.45	0.49	0.43	0.76
Diluted income per common share	0.44	0.48	0.42	0.75
2004				
Revenues	$ 59,291	$ 70,122	$ 79,252	$ 89,868
Operating income	30,249	34,201	38,010	43,398
Net income	16,902	17,991	21,014	26,240
Basic income per common share	0.37	0.40	0.43	0.54
Diluted income per common share	0.37	0.39	0.43	0.53

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Item 9. ***Changes in and Disagreements with Accountants On Accounting And Financial Disclosure***

None.

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

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that, as of December 31, 2005, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in applicable rules and forms.

Management s Report on Internal Control Over Financial Reporting

The Company s management is responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control over financial reporting is a process designed under the supervision of the Company s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2005, management assessed the effectiveness of the Company s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on those criteria.

Ernst & Young, LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual report on Form 10-K, has issued an attestation report on management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005. The report, which expresses unqualified opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, is included in this Annual Report on Form 10-K, Item 9A. under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting.

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Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

To the Board of Directors and Shareholders of
Encore Acquisition Company:

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting appearing under Item 9A, that Encore Acquisition Company and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Management of the Company is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the internal control over financial reporting of the Company based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2005, and our report dated March 3, 2006 expressed an unqualified opinion on thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
March 3, 2006

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Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information required in response to this item is or will be set forth in the Company s definitive proxy statement for the 2006 annual meeting of stockholders and is incorporated herein by reference.

We have adopted a Code of Business Conduct and Ethics covering our directors, officers, and employees, which is available free of charge on our Internet website (www.encoreacq.com). We will post on our web site any amendments to the Code of Business Conduct and Ethics or waivers of the Code of Business Conduct and Ethics for directors and executive officers.

Item 11. ***Executive Compensation***

The information required in response to this item is or will be set forth in the Company s definitive proxy statement for the 2006 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item is or will be set forth in the Company s definitive proxy statement for the 2006 annual meeting of stockholders and is incorporated herein by reference.

The following table sets forth information about the Company s common stock that may be issued under the Company s equity compensation plans as of December 31, 2005:

	(a)	(b)	(c)
	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights(2)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders(1)	1,440,812	$ 13.20	1,656,960
Equity compensation plans not approved by security holders			
Total	1,440,812	$ 13.20	1,656,960

(1) The 2000 Incentive Stock Plan is the Company s only equity compensation plan.

(2) Excludes 583,287 shares of restricted stock.

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Item 13. ***Certain Relationships and Related Transactions***

The information required in response to this item is or will be set forth in the Company s definitive proxy statement for the 2006 annual meeting of stockholders and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees And Services***

The information required in response to this item is or will be set forth in the Company s definitive proxy statement for the 2006 annual meeting of stockholders and is incorporated herein by reference.

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PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) The following documents are filed as a part of this Report:

1. *Financial Statements:*

2. *Financial Statement Schedules:*

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to the consolidated financial statements.

(b) *Exhibits*

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

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INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.1.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2005, filed with the SEC on May 5, 2005).
3.2	Second Amended and Restated Bylaws of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
4.1	Specimen certificate of the Company (incorporated by referenced to Exhibit 4.1 to Registration Statement on Form S-1, Registration No. 333-47540, filed with the SEC on December 15, 2000).
4.2.1	Indenture, dated as of April 2, 2004, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.1 of the Company s Registration Statement on Form S-4 (Registration No. 333-117025) filed with the SEC on June 30, 2004).
4.2.2	Form of 6.25% Senior Subordinated Note to Cede & Co. or its registered assigns (included as Exhibit A to Exhibit 4.2.1 above).
4.3.1	Indenture, dated as of July 13, 2005, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association with respect to the 6% Senior Subordinated Notes due 2015 (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K, filed with the SEC on July 14, 2005).
4.3.2	Form of 6% Senior Subordinated Note due 2015 (included as Exhibit A to Exhibit 4.3.1 above).
4.4.1	Indenture, dated as of November 16, 2005, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association with respect to Subordinated Debt Securities (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K, filed with the SEC on November 23, 2005).
4.4.2	First Supplemental Indenture, dated as of November 16, 2005, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association with respect to the $7^1/4$% Senior Subordinated Notes due 2017 (incorporated by reference to Exhibit 4.2 to the Company s Current Report on Form 8-K, filed with the SEC on November 23, 2005).
4.4.3	Form of $7^1/4$% Senior Subordinated Note due 2017 (included as Exhibit A to Exhibit 4.4.2 above).
10.1+	2000 Incentive Stock Plan (incorporated by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-8 (File No. 333-120422), filed with the SEC on November 12, 2004).

10.2+	Employee Severance Protection Plan (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003, filed with the SEC on May 8, 2003).
10.3+*	Form of Restricted Stock Award Executive.
10.4+*	Form of Stock Option Agreement (Nonqualified).
10.5+*	Form of Stock Option Agreement (Incentive).
10.6+	Form of Indemnification Agreement for directors and executive officers (incorporated by reference to Exhibit 10.6 of the Company s 2004 Annual Report on Form 10-K for the year ended December 31, 2004).

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Exhibit No.	Description
10.7+*	Table of 2006 Base Salaries for Executive Officers of the Company
10.8	Description of Compensation Payable to Non-Management Directors (incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed with the SEC on February 22, 2006).
10.9	Amended and Restated Credit Agreement, dated August 19, 2004, among the Company, Encore Operating, L.P., Bank of America, N.A., as Administrative Agent, Fotis Capital Corp. and Wachovia Bank, N.A., as Co-Syndication Agents, BNP Paribas and Citibank, N.A., as Co-Documentary Agents and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K, filed with the SEC on August 25, 2004).
10.10	First Amendment to Credit Agreement, dated April 29, 2005 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed with the SEC on May 4, 2005).
10.11	Second Amendment to Credit Agreement, dated November 14, 2005 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed with the SEC on November 18, 2005).
10.12	Third Amendment to Credit Agreement, dated December 29, 2005 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed with the SEC on January 5, 2006).
10.13	Registration Rights Agreement, dated August 18, 1998, by and among the Company and the other parties thereto (incorporated by reference to Exhibit 4.2 to the Company s Registration Statement on Form S-1 (File No. 333-47540), filed with the SEC on October 6, 2000).
10.14+*	Severance Agreement, dated November 28, 2005, between the Company and Roy W. Jageman.
21.1*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Miller and Lents, Ltd.
24.1*	Power of Attorney (included on the signature page of this report).
31.1*	Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer)
31.2*	Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer)
32.1*	Section 1350 Certification (Principal Executive Officer)
32.2*	Section 1350 Certification (Principal Financial Officer)

* Filed herewith
+ Management contract or compensatory plan, contract or arrangement

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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, on the 7th day of March, 2006.

Encore Acquisition Company

By /s/ Jon S. Brumley

Jon S. Brumley

Chief Executive Officer and President

KNOW ALL MEN BY THESE PRESENTS, that each individual whose signature appears below constitutes and appoints Jon S. Brumley and Louie B. Nivens, Jr., and each of them, his true and lawful attorneys-in-fact and agents with full power of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this report, and to file the same, with all exhibits thereto, and all documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or his or their substitutes, may lawfully do or cause to be done by virtue hereof.

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 in the capacities indicated on March 7, 2006.

Signature	Title or Capacity
/s/ I. Jon Brumley I. Jon Brumley	Chairman of the Board and Director
/s/ Jon S. Brumley Jon S. Brumley	Chief Executive Officer, President and Director (Principal Executive Officer)
/s/ Louie B. Nivens, Jr. Louie B. Nivens, Jr.	Chief Financial Officer, Treasurer, Senior Vice President and Corporate Secretary (Principal Financial Officer)
/s/ Robert C. Reeves Robert C. Reeves	Senior Vice President, Chief Accounting Officer, Controller, and Assistant Corporate Secretary
/s/ Martin C. Bowen Martin C. Bowen	Director
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director

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Signature	Title or Capacity
/s/ Ted A. Gardner Ted A. Gardner	Director
/s/ John V. Genova John V. Genova	Director
/s/ James A. Winne III James A. Winne III	Director