DENBURY RESOURCES INC.

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FINANCIAL HIGHLIGHTS

Amounts in thousands, unless otherwise noted	YEAR ENDED DECEMBER 31, 2005	2004[2]	2003	2002	2001[2]	AVERAGE ANNUAL GROWTH[1]
CONSOLIDATED STATEMENTS OF OPERATIONS DATA:						
Revenues	**$ 560,392**	$ 382,972	$ 333,014	$ 285,152	$ 285,111	18%
Net income	**166,471**	82,448	56,553[3]	46,795	56,550	31%
Net income per common share[4]:						
Basic	**$ 1.49**	$ 0.75	$ 0.52[3]	$ 0.44	$ 0.57	27%
Diluted	**1.39**	0.72	0.51[3]	0.43	0.56	26%
Weighted average number of common shares outstanding[4]:						
Basic	**111,743**	109,741	107,763	106,487	98,650	3%
Diluted	**119,634**	114,603	110,928	108,730	100,722	4%
CONSOLIDATED STATEMENTS OF CASH FLOW DATA:						
Cash provided by (used for):						
Operating activities	**$ 360,960**	$ 168,652	$ 197,615	$ 159,600	$ 185,047	18%
Investing activities	**(383,687)**	(93,550)	(135,878)	(171,161)	(318,830)	5%
Financing activities	**154,777**	(66,251)	(61,489)	12,005	134,986	3%
PRODUCTION (DAILY):						
Oil (Bbls)	**20,013**	19,247	18,894	18,833	16,978	4%
Natural gas (Mcf)	**58,696**	82,224	94,858	100,443	85,238	(9%)
BOE (6:1)	**29,795**	32,951	34,704	35,573	31,185	(1%)
UNIT SALES PRICE (EXCLUDING HEDGES):						
Oil (per Bbl)	**$ 50.30**	$ 36.46	$ 27.47	$ 22.36	$ 21.34	24%
Natural gas (per Mcf)	**8.48**	6.24	5.66	3.31	4.12	20%
UNIT SALES PRICE (INCLUDING HEDGES):						
Oil (per Bbl)	**$ 50.30**	$ 27.36	$ 24.52	$ 22.27	$ 21.65	23%
Natural gas (per Mcf)	**7.70**	5.57	4.45	3.35	4.66	13%
COSTS PER BOE:						
Lease operating expenses	**$ 9.98**	$ 7.22	$ 7.06	$ 5.48	$ 4.84	20%
Production taxes and marketing expenses	**2.54**	1.55	1.17	0.92	0.96	28%
General and administrative	**2.62**	1.78	1.20	0.96	0.89	31%
Depletion, depreciation, and amortization	**9.09**	8.09	7.48	7.26	6.27	10%
PROVED RESERVES:						
Oil (MBbls)	**106,173**	101,287	91,266	97,203	76,490	9%
Natural gas (MMcf)	**278,367**	168,484	221,887	200,947	198,277	9%
MBOE (6:1)	**152,568**	129,369	128,247	130,694	109,536	9%
CONSOLIDATED BALANCE SHEET DATA:						
Total assets	**$1,505,069**	$ 992,706	$ 982,621	$ 895,292	$ 789,988	17%
Total long-term liabilities	**617,343**	368,128	434,845	432,616	360,882	14%
Stockholders' equity[5]	**733,662**	541,672	421,202	366,797	349,168	20%

(1) Four-year compounded annual growth rate computed using 2001 as a base year.

(2) We sold Denbury Offshore, Inc. in July 2004. We acquired Matrix Oil and Gas Inc. in July 2001.

(3) In 2003, we recognized a gain of $2.6 million for the cumulative effect of the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 4 to the Consolidated Financial Statements). In April 2003, we recorded a pre-tax charge of $17.6 million associated with early debt retirement.

(4) On October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years and earnings per share has been retroactively restated to reflect the stock split.

(5) We have never paid any dividends on our common stock.

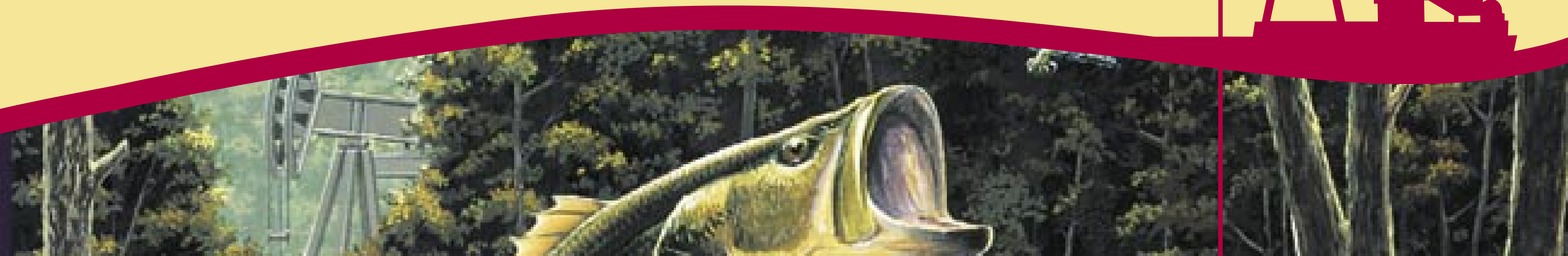
Reporting Format: Unless otherwise noted, the disclosures in this report have (i) production volumes expressed on a net revenue interest basis, and (ii) gas volumes converted to equivalent barrels at 6:1.
See page 28 regarding cautionary notes about forward-looking statements and unproved reserves contained herein.

BUILDING ON SOLID GROUND

DENBURY RESOURCES INC. 2005 ANNUAL REPORT

We had another outstanding year during 2005, extending a run of several years wherein each year is better than the previous one. With our current strategy, we believe we can continue this trend and produce strong results for many years into the future. The building blocks for those years are celebrated in this year's annual report by looking back at the notable achievements during the last ten years during which we have been a U.S. public company.

Below: A Largemouth Bass leaping for a dragonfly. The scene illustrated takes place very near Davis Field in Mississippi. This illustration was featured on the cover of the Denbury Resources 1995 Annual Report.



DRI

DENBURY RESOURCES INC. 1995 & 1996 ANNUAL REPORTS

We produced our first U.S. annual report in 1995. That year, we had changed our name to Denbury Resources, and Texas Pacific Group made their first investment in the company of $40 million.

The highlight of 1996 was the acquisition of core fields in Mississippi and Louisiana from Amerada Hess for $37.2 million. The key field in the Mississippi acquisition, Eucutta, was an immediate success as we started to lay the groundwork for our understanding of the CO_2 flood process.

Below: Part of an illustration from the Denbury Resources 1996 Annual Report.

TO OUR SHAREHOLDERS:

We had another outstanding year during 2005, extending a run of several years wherein each year is better than the previous one. With our current strategy, we believe we can continue this trend and produce strong results for many years into the future. The building blocks for those years are celebrated in this year's annual report by looking back at the notable achievements during the last ten years during which we have been a U.S. public company.

Most significantly for you as a stockholder, during the last couple of years, our stock price performance has been superb, as stockholders recognized our operational performance and unique strategy, assisted of course by high commodity prices. Our share price has outperformed most of our peer group as the financial markets gave value for our potential long-term growth of production and reserves through CO_2 tertiary flooding.

During 1996 and 1997, Denbury Resources earned total net income of $23.6 million, less than half of the $57.2 million we earned in just the 4th quarter of 2005.

2005 ACCOMPLISHMENTS:

We had a notable year because we:

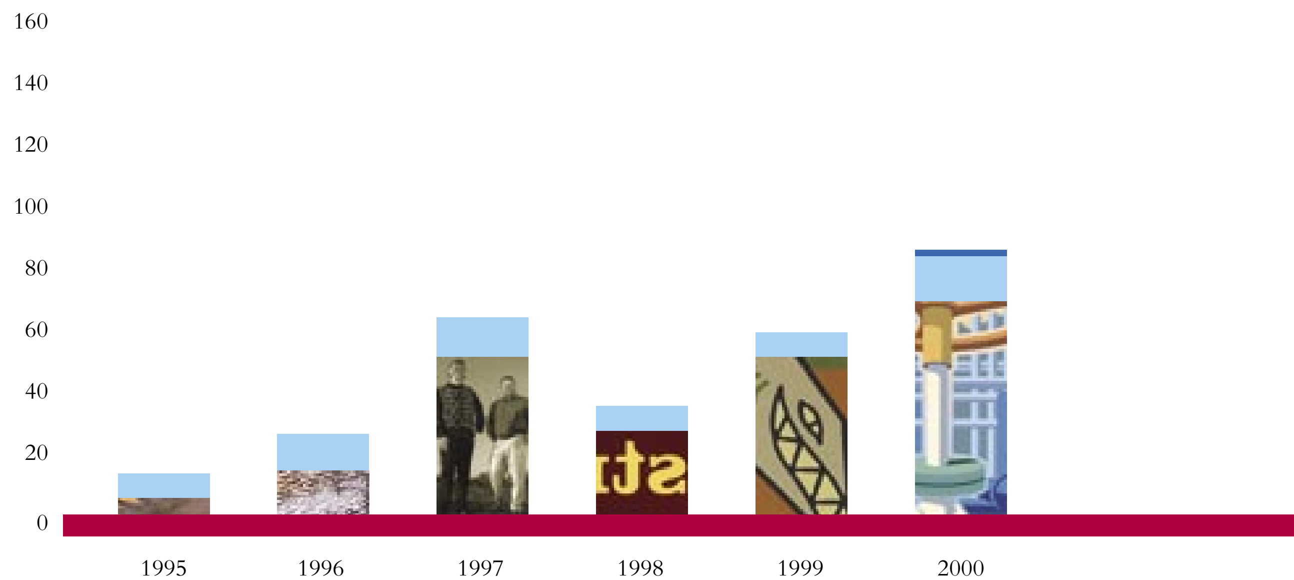
- ***Increased our CO_2 reserves at Jackson Dome by 74%***

  Our proved gross CO_2 reserves at Jackson Dome increased from 2.7 Tcf last year-end to 4.6 Tcf as of December 31, 2005. We expect this to be sufficient to recover an estimated 300 MMBbls from CO_2 tertiary flooding, 260 MMBbls of which we have already identified as potential in existing Denbury fields. With the potential to recycle CO_2 after a flood is complete, the ultimate potential oil recovery from tertiary flooding could possibly even double. Furthermore, we believe that we have incremental probable CO_2 reserves at Jackson Dome (our CO_2 source area) in the range of 3 to 4 Tcf, suggesting that the ultimate potential recoverable oil reserves could possibly double again.

- ***Completed our Free State CO_2 Pipeline to East Mississippi***

  We began filling this 84-mile-long pipeline with CO_2 during February 2006 and by March or April, plan to initiate tertiary flooding at three fields in East Mississippi. This pipeline will be capable of transporting up to 400 MMcf/d of CO_2 from Jackson Dome to our Phase II fields. We expect to recover an estimated 80 MMBbls of oil from the initial six tertiary floods in this area, approximately 9 MMBbls of which are proven reserves, with the remainder probable. There are other potential floodable fields in this area, only a few of which we currently own, that could further increase the potential in East Mississippi. This may be the first of many other pipeline projects as we continue to develop CO_2 tertiary oil reserves throughout the region.

Proved Reserves
(MBOE)



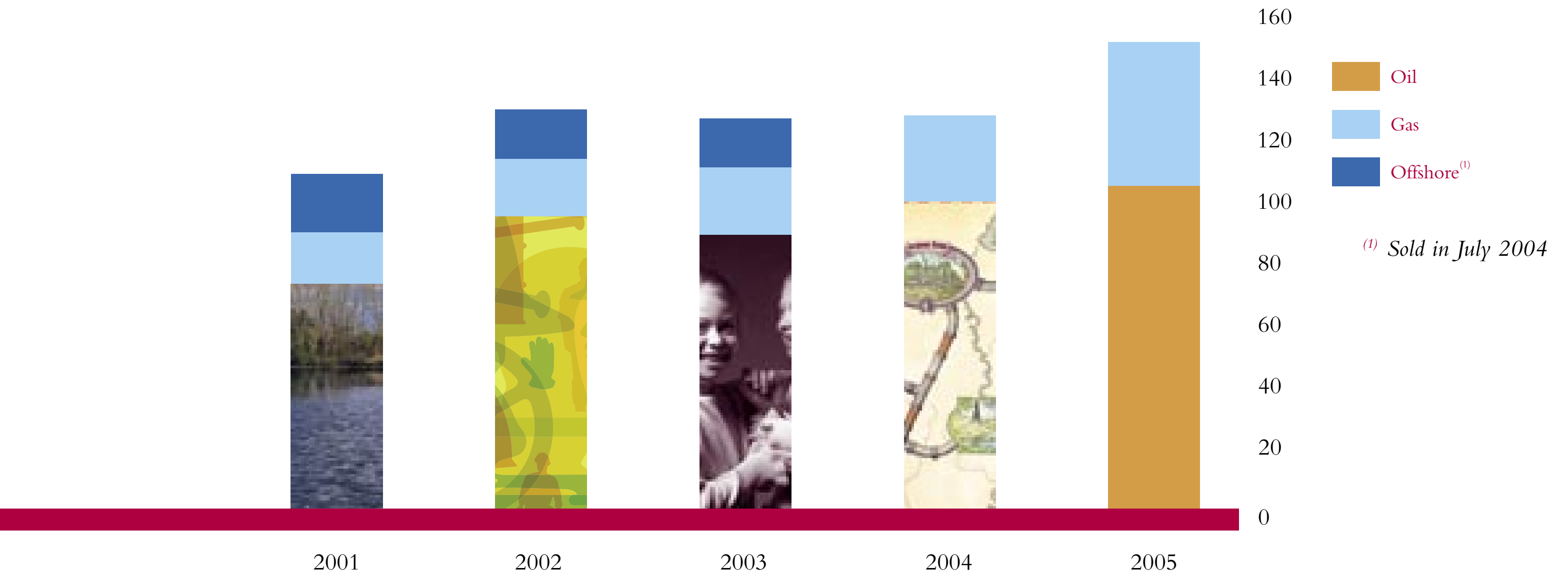
- ***Increased tertiary oil production by 36% year over year***

  During the 4th quarter of 2005, our oil production from CO_2 floods in Southwest Mississippi (Phase I) averaged 9,939 Bbls/d, a 37% increase from the fourth quarter of 2004 average of 7,242 Bbls/d. On an annual basis, we increased production by 36%, averaging 9,215 Bbls/d during 2005. Our latest flood, at Brookhaven Field, began to respond in late 2005, making it the fourth such field to respond since we began to expand our tertiary operations following our original acquisition at Little Creek in 1999.

- ***Continued to buy mature oil fields for future CO_2 flooding***

  In January 2006, we closed on a $248 million acquisition of three producing oil properties that are future potential CO_2 tertiary flood candidates: Tinsley Field, located approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near our Eucutta Field. In addition to 14.4 MMBOEs of proven producing reserves, we believe that these properties have up to 80 MMBbls of potential oil reserves that may potentially be recovered using CO_2. We plan to flood Tinsley Field as part of our Phase III operations with initial work planned for 2006 and more extensive development during 2007. The timing of Citronelle Field is less certain as it will require a 60- to 70-mile extension of our Free State CO_2 Pipeline, but it will likely be flooded as a future phase.

  During 2005, we acquired majority interests in two fields west of our original Phase I, which we are calling our Phase IV. We also entered into



an agreement to acquire a 102-mile natural gas pipeline that runs from our existing CO_2 pipeline to these fields. Once acquired, we plan to convert this natural gas line to CO_2 service for Phase IV. This project is subject to regulatory approval and also requires the construction of a smaller, shorter replacement natural gas line before it can be utilized for CO_2 service.

- ***Expanded our horizontal well drilling in the Barnett Shale***

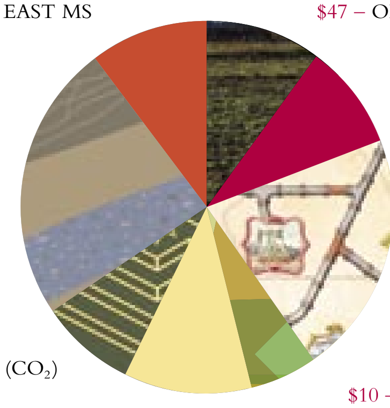
  During 2005, we drilled a total of 23 horizontal wells in our northern Barnett Shale acreage, increasing the number of rigs from one to four by the first quarter of 2006. We increased our net acreage position by 182% to approximately 50,000 net acres, our production by more than threefold to 18.3 MMcfe/d by the 4th quarter of 2005, and our proved reserves by 152% to 157 Bcf as of December 31, 2005. We plan to drill 45 to 50 wells here during 2006, about a dozen of which will test our southern acreage in Erath and surrounding counties.

- ***Increased our overall company reserves and production***

  Our total proved reserves grew by 18% to 153 MMBOE, a reserve replacement ratio of approximately 313%, with over 85% of the new reserves generated by internal organic growth. Our average daily production (adjusted for the offshore sale during 2004) grew by 6% during 2005 to an annual average of 29,795 BOE/d, despite over 1,100 BOE/d deferred as a result of two hurricanes.

2005 Capital Spending

(in millions)



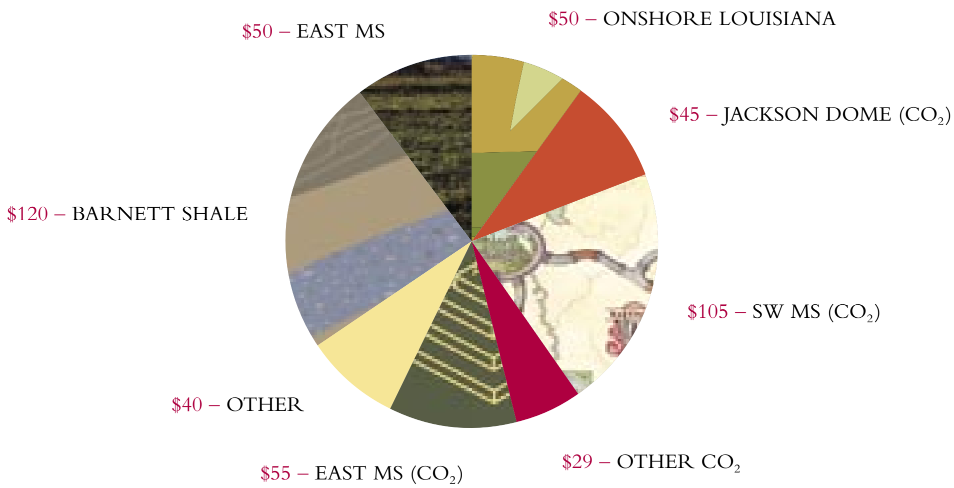
STRATEGY

Simply put, our strategy is to grow oil production and reserves using our CO_2 reserves at Jackson Dome. In order to accomplish this we must first add CO_2 reserves and deliverability at Jackson Dome, followed by the selection of suitable oil fields (often pursuant to an acquisition), the potential construction of a pipeline to deliver CO_2 to the oil fields, and finally the injection of CO_2 into the reservoir. We have been able to add significant reserves from CO_2 floods over the last 3 years and expect that the majority of our future reserve increases in the future will come from this play.

Meanwhile we continue to invest in the Barnett Shale play in Texas and to a lesser extent in South Louisiana, both with excellent results during 2005. The Barnett Shale play is an important area for Denbury and the risk-reward profile compares favorably to our CO_2 play. In South Louisiana, we have been conducting a small, but quality exploration and development program, driven by some in-house seismic work, and the recent results have been impressive.

In past years, we have often featured our employees and highlighted their contribution to our success, and this year, faced with rising costs and a shortage of experienced industry people, the loyalty and hard work of our work force has made an even more important contribution. We have had a policy, since inception, to provide equity participation for all of our employees through a progressive stock purchase plan and a rolling stock option and long-term award program. This has contributed to a very low turnover rate for us and has helped us meet our expansion needs. The availability of qualified personnel has become a critical factor in our industry today and could become a potential constraint in the timely execution of our CO_2 strategy.

2006 Capital Budget
(in millions)



OUTLOOK

We now have more than enough proved reserves of CO_2 at Jackson Dome to flood our planned projects. We are continuing to drill wells at Jackson Dome, where we estimate there could be significant additional reserves of CO_2 to further increase our proven CO_2 reserves over the next few years. We believe there are about 3 to 4 Tcf of probable CO_2 reserves in the area, an amount that could almost double our proven CO_2 reserves and correspondingly, potentially double the oil volumes that can be extracted. Our internal studies support the conclusions of a DOE study released in March 2005 which stated that between 2.6 and 5.8 billion barrels of oil could feasibly be recovered from CO_2 flooding in the Gulf Coast region. We believe that the single biggest factor in extracting this oil will be the availability of CO_2 itself. Given the low costs and favorable economics of our CO_2, we are uniquely positioned to take advantage of this opportunity.

We believe that we can expect strong reserve and production growth for the next several years based on the fields in our planned tertiary Phases I through IV. As additional CO_2 volumes are proven, we will be in a position to expand our growth for many more years. This puts us in a position to organically add oil reserves, a position that few others will be able to match. We look forward to the next 10 years of growth at Denbury as we continue to build on the solid foundation that we have developed to date.

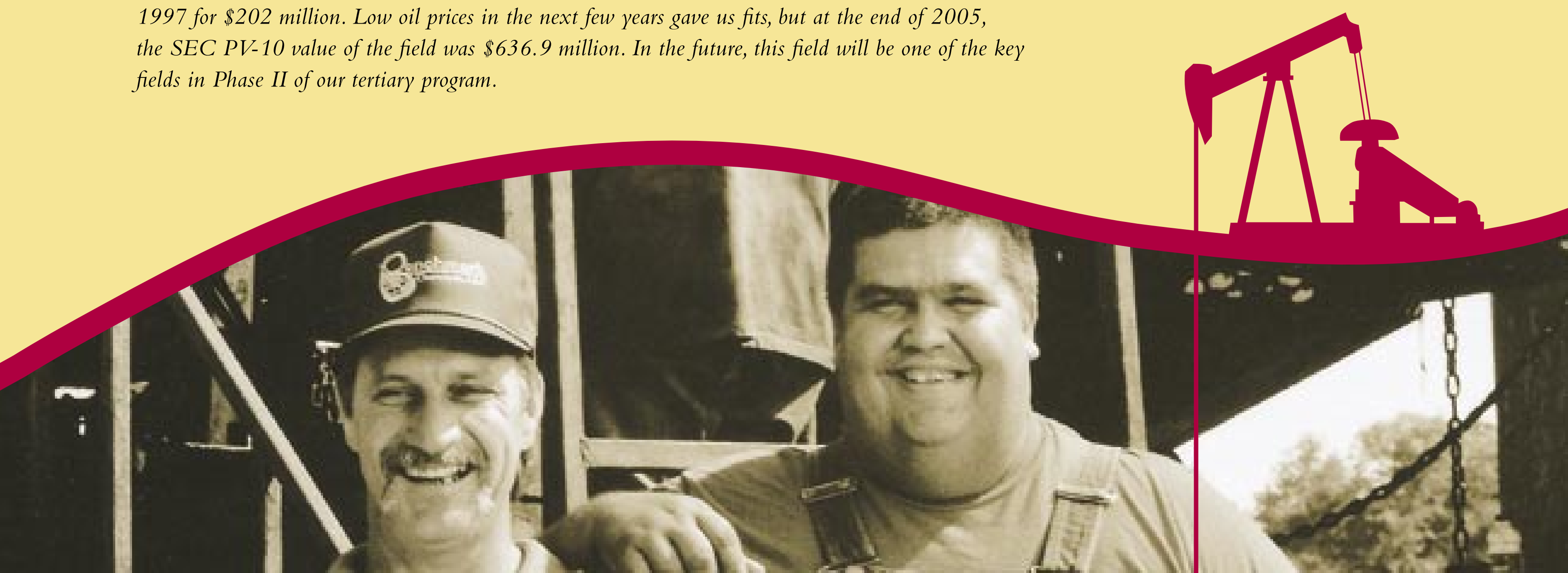
Gareth Roberts
President and Chief Executive Officer
March 7, 2006

People. Denbury's Most Valuable Natural Resource.
DENBURY RESOURCES INC. 1997 ANNUAL REPORT

"Denbury recognizes that its success over the past five years is largely due to the dedication and effort of its employees… All of the Company's employees are shareholders through the Company's stock option plan and 86% of the Company's employees participate in the stock purchase plan… The dedication and resourcefulness of our employees give management the confidence that the Company can meet and overcome any future challenges."

Gareth Roberts
Denbury Resources Inc. 1997 Annual Report
Letter to Shareholders

1997
Emboldened by our success at Eucutta, we purchased Heidelberg Field, the biggest in the basin, in late 1997 for $202 million. Low oil prices in the next few years gave us fits, but at the end of 2005, the SEC PV-10 value of the field was $636.9 million. In the future, this field will be one of the key fields in Phase II of our tertiary program.



Selected Operating Data

OIL AND GAS RESERVES

DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas, prepared estimates of our net proved oil and natural gas reserves as of December 31, 2005, 2004 and 2003. The reserve estimates were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission (SEC). The prices used in preparation of the reserve estimates were based on the market prices in effect as of December 31 of each year, with the appropriate adjustments (transportation, gravity, basic sediment and water (BS&W), purchasers' bonuses, Btu, etc.) applied to each field. The reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interests in our properties.

Our proved nonproducing reserves primarily relate to reserves that are to be recovered from productive zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties typically have both proved producing and proved nonproducing reserves.

Proved undeveloped reserves associated with our CO_2 tertiary operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 97% of our proved undeveloped oil reserves. We consider these reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production because all of these proved undeveloped reserves are associated with secondary recovery or tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production. The main reason these reserves are classified as undeveloped is because they require significant additional capital associated with drilling/re-entering wells or additional facilities in order to produce the reserves and/or are waiting for a production response to the water or CO_2 injections.

Our proved undeveloped natural gas reserves associated with our Selma Chalk play at Heidelberg and the Barnett Shale play account for approximately 95% of our proved undeveloped natural gas reserves. The remaining undeveloped natural gas reserves are spread over multiple fields. Our current plans for 2006 include development of 70 to 80 wells in our two primary natural gas plays, the Barnett Shale and Selma Chalk.

Many of Denbury's employees have been with the company for over 10 years. Part of what we are built on is the strength of their commitment and experience. In the page opposite are two of our valued employees featured in our 1997 Annual Report. Below we feature them again, still dedicated to the success of Denbury Resources.

RICK FIELDS *and* TIMMY SANCHEZ
Eucutta, Mississippi
1994 to the Present

MBbls: One thousand barrels of crude oil or other liquid hydrocarbons
MMcf: One million cubic feet of natural gas or CO_2
MBOE: One thousand BOEs

See page 3 of our Form 10-K for glossary and selected abbreviations.

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
ESTIMATED PROVED RESERVES:			
Oil (MBbls)	**106,173**	101,287	91,266
Natural gas (MMcf)	**278,367**	168,484	221,887
Oil equivalent (MBOE)	**152,568**	129,369	128,247
PERCENTAGE OF TOTAL MBOE:			
Proved producing	**40%**	39%	43%
Proved nonproducing	**16%**	16%	18%
Proved undeveloped	**44%**	45%	39%
REPRESENTATIVE OIL AND GAS PRICES: (1)			
Oil – NYMEX	**$ 61.04**	$ 43.45	$ 32.52
Natural gas – Henry Hub	**10.08**	6.18	5.97
PRESENT VALUES:(2)			
Discounted estimated future net cash flow before income taxes ("PV-10 Value") (thousands)	**$3,215,478**	$1,643,289	$1,566,371
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	**2,084,449**	1,129,196	1,124,127

(1) The prices as of each year-end were based on market prices in effect as of December 31 of each year, NYMEX prices per Bbl and NYMEX Henry Hub prices per MMBtu, with the appropriate adjustments (transportation, gravity, BS&W, purchasers' bonuses, Btu, etc.) applied to each field to arrive at the appropriate corporate net price.

(2) Determined based on year-end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum.

FIELD SUMMARIES

Denbury operates in four primary areas: Louisiana, Eastern Mississippi, Western Mississippi and Texas. Our 13 largest fields (listed on the opposite page) constitute approximately 91% of our total proved reserves on a BOE basis and 90% on a PV-10 Value basis. Within these 13 fields, we own a weighted average 94% working interest and operate all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve and allows us to effectively manage the properties from our three primary field offices in Houma, Louisiana, Laurel, Mississippi, and Cleburne, Texas.

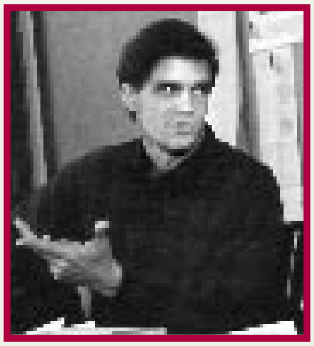
	PROVED RESERVES AS OF DECEMBER 31, 2005[1]					2005 AVERAGE PRODUCTION		
	OIL (MBbls)	NATURAL GAS (MMcf)	MBOE	BOE % OF TOTAL	PV-10 VALUE (000's)	OIL (Bbls/d)	NATURAL GAS (Mcf/d)	AVERAGE NET REVENUE INTEREST
MISSISSIPPI CO_2 FLOODS								
Brookhaven	19,273	—	19,273	12.6%	$405,761	31	—	81.9%
Mallalieu (East & West)	13,164	—	13,164	8.6%	452,306	4,739	—	76.6%
McComb/Olive	10,268	—	10,268	6.7%	277,894	908	—	75.6%
Little Creek & Lazy Creek	5,103	—	5,103	3.4%	156,377	3,529	—	83.3%
Smithdale	2,890	—	2,890	1.9%	68,345	8	—	79.5%
Eucutta	9,110	—	9,110	6.0%	102,427	—	—	82.8%
Total MS CO_2 floods	59,808	—	59,808	39.2%	1,463,110	9,215	—	79.7%
OTHER MISSISSIPPI								
Heidelberg (East & West)	29,077	54,784	38,208	25.0%	636,856	4,957	14,133	75.9%
Eucutta	4,368	—	4,368	2.9%	74,810	986	47	81.4%
King Bee	1,792	—	1,792	1.2%	29,937	377	—	79.4%
Other Mississippi	8,195	11,898	10,178	6.7%	188,067	2,867	3,130	38.0%
Total Other Mississippi	43,432	66,682	54,546	35.8%	929,670	9,187	17,310	64.3%
LOUISIANA								
Thornwell	1,206	13,049	3,381	2.2%	132,482	377	4,838	40.4%
S. Chauvin	501	15,581	3,098	2.0%	112,859	241	6,963	36.1%
Lirette	85	7,861	1,395	0.9%	59,978	193	7,002	67.8%
Other Louisiana	1,027	16,426	3,765	2.5%	137,103	771	8,687	35.5%
Total Louisiana	2,819	52,917	11,639	7.6%	442,422	1,582	27,490	39.3%
TEXAS								
Newark (Barnett Shale)	—	156,858	26,143	17.1%	370,535	5	12,844	74.3%
OTHER	114	1,910	432	0.3%	9,741	24	1,052	0.6%
Company Total	106,173	278,367	152,568	100.0%	$3,215,478	20,013	58,696	52.4%

(1) *The reserves were prepared using constant prices and costs in accordance with the guidelines of the SEC based on the prices received on a field-by-field basis as of December 31, 2005. The prices at that date were a NYMEX oil price of $61.04 per Bbl adjusted to prices received by field and a Henry Hub natural gas price average of $10.08 per MMBtu also adjusted to prices received by field.*

There's more than one way to look at the oil and natural gas industry.
DENBURY RESOURCES INC. 1998 ANNUAL REPORT

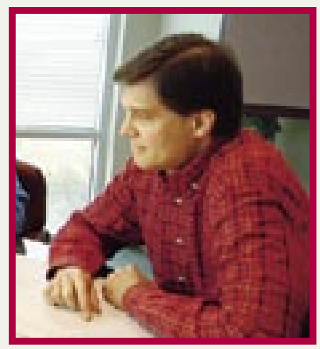
1998 was not our best year. Lots of hard work, but low oil prices forced us to make some difficult choices. However, we did lay more groundwork by looking at the oil and natural gas industry in different ways than our competitors.

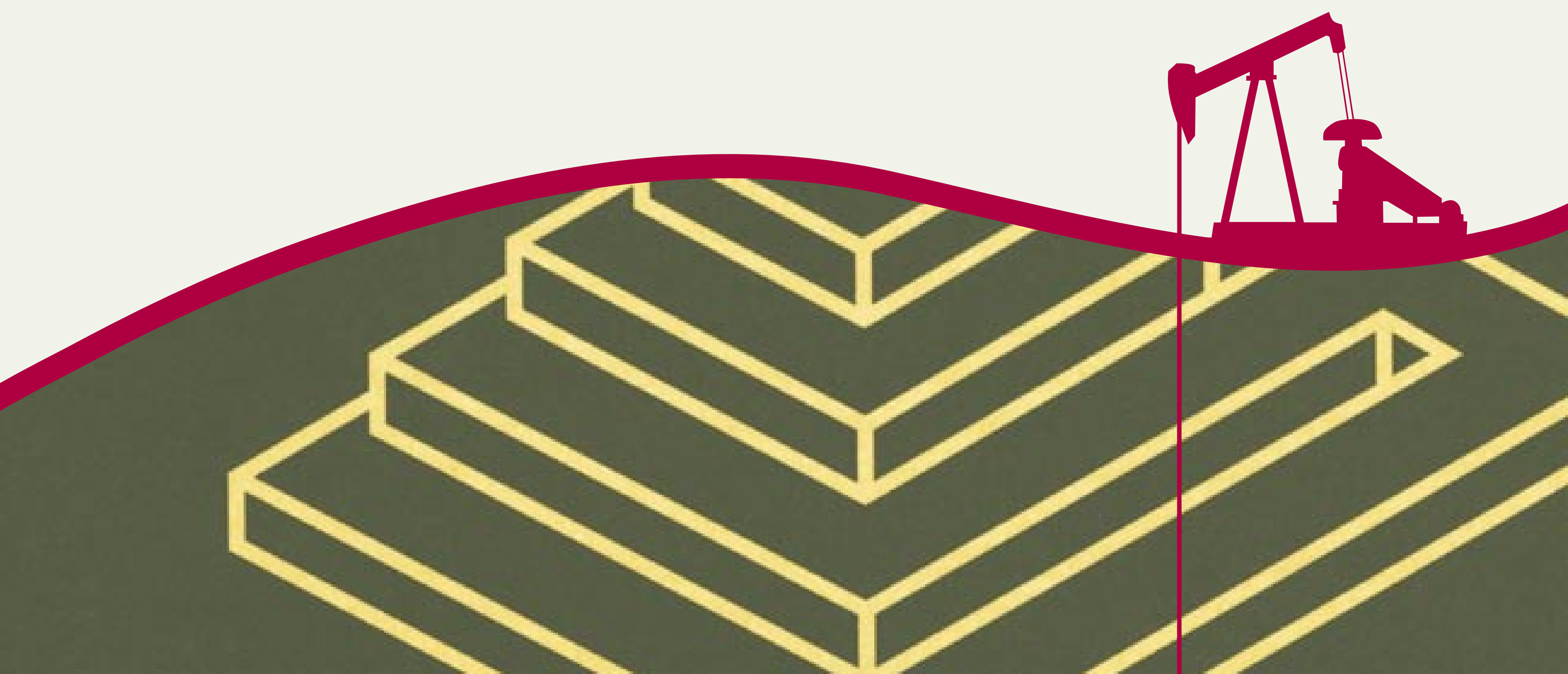
Below: Part of an illustration from our 1998 Annual Report. Opposite page: A section of the properties map featured in the 1999 Annual Report.

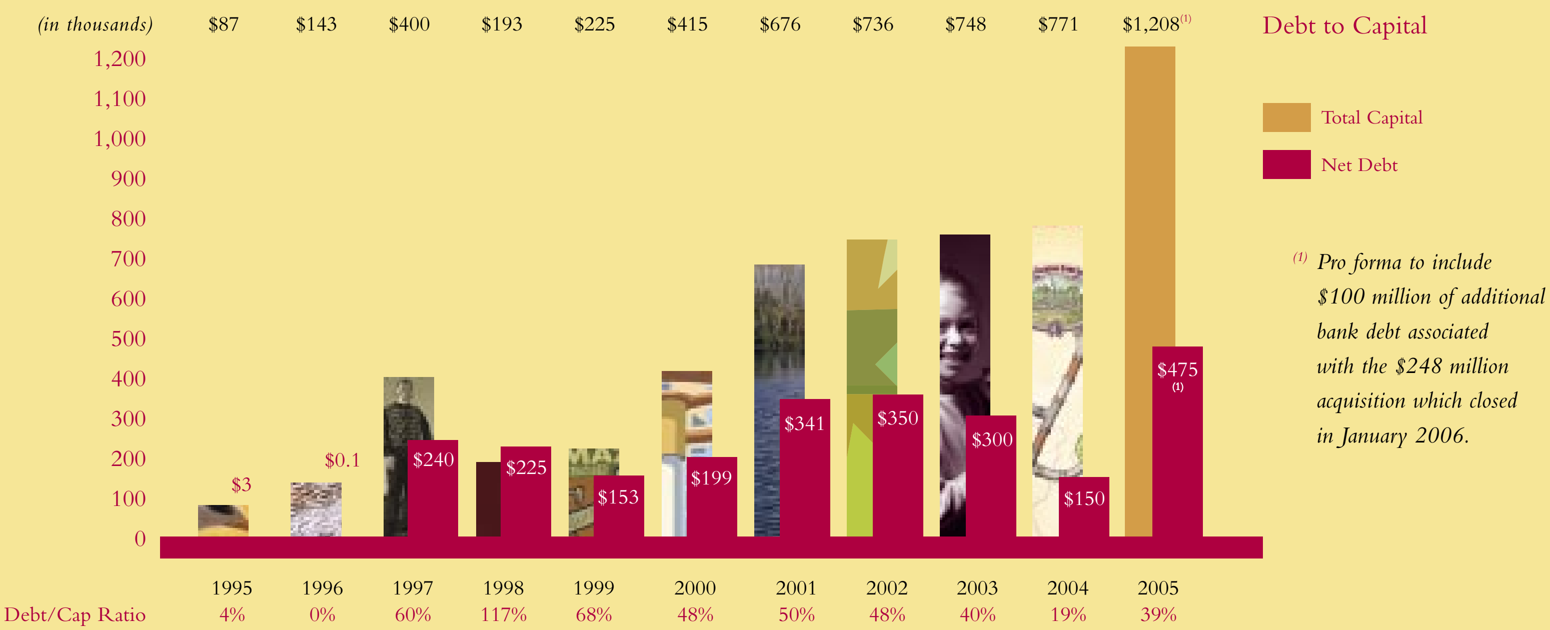


Above: PHIL RYKHOEK, *Senior Vice President & Chief Financial Officer (left), explains why oil will be $60/Bbl in seven years' time to* GARETH ROBERTS, *President & Chief Executive Officer (center) and* MARK WORTHEY, *Senior Vice President, Operations (right). Original photography featured in the 1998 annual report. Featured below, 2006, older and wiser.*



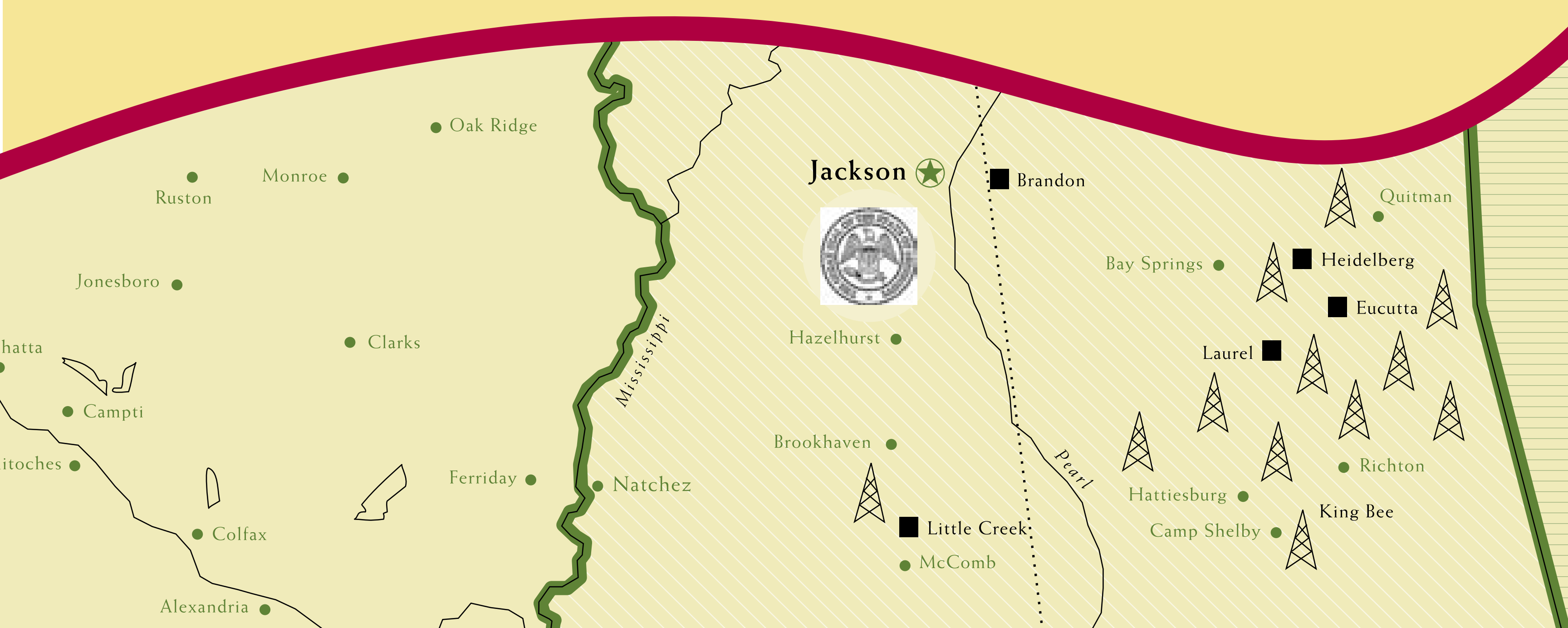


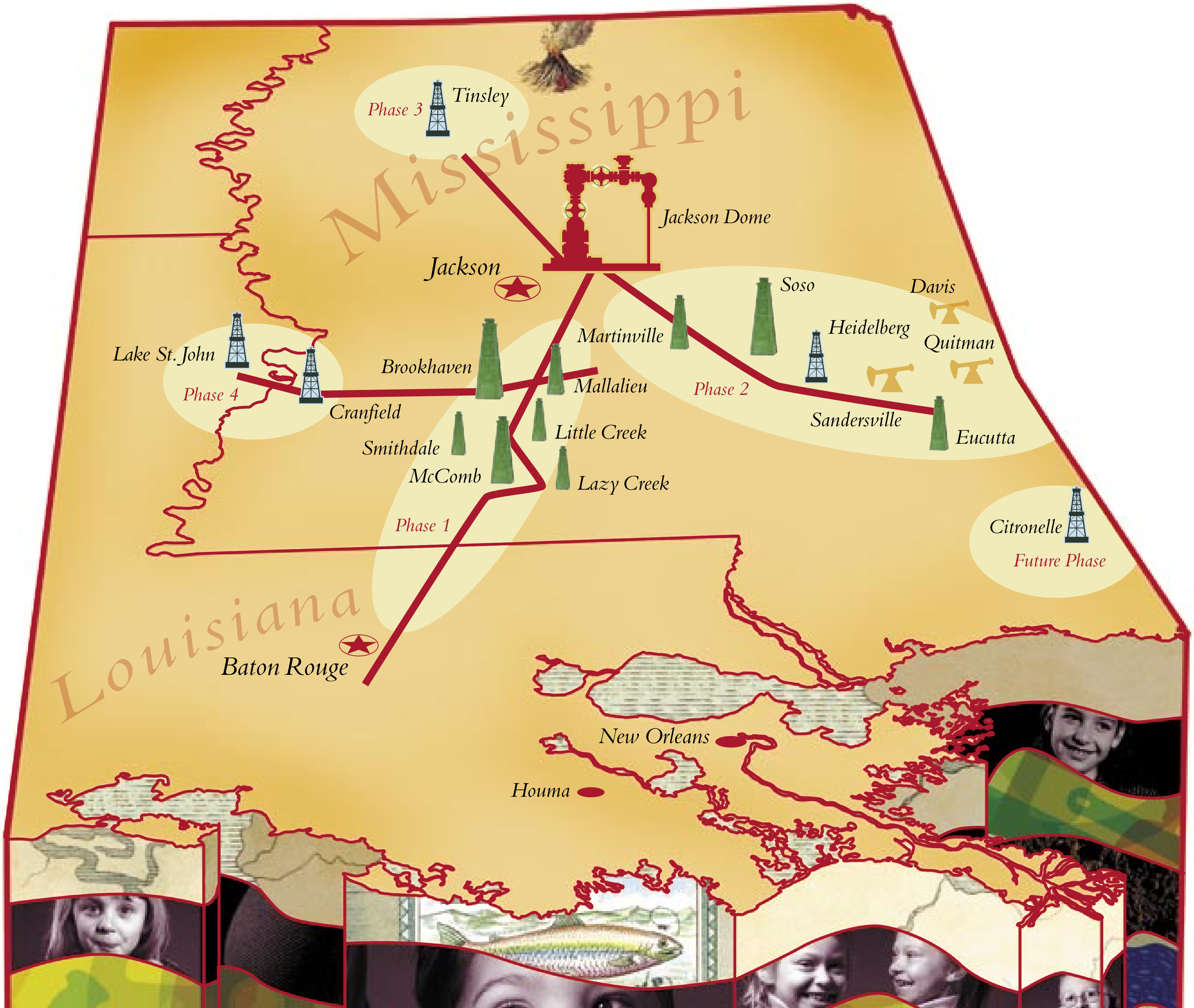




In 1999, Little Creek arrived with little fanfare, but our success showed promise for our CO_2 play. A capital infusion of $100 million from Texas Pacific Group allowed us to pursue our new strategy.

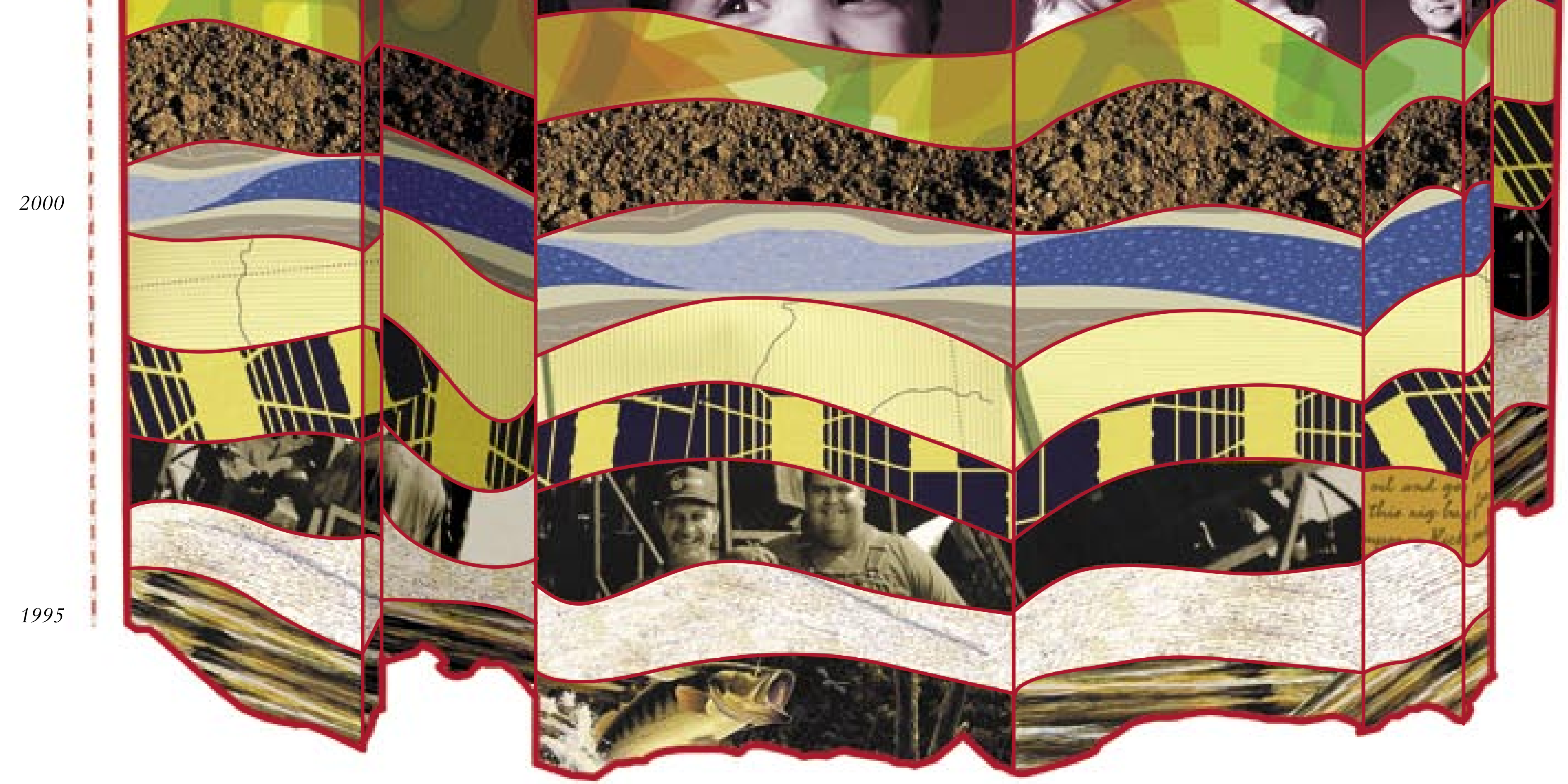
Denbury Resources Inc. 1999 Annual Report





Mississippi
Louisiana
Phase 3
Tinsley
Jackson Dome
Jackson
Lake St. John
Phase 4
Cranfield
Brookhaven
Martinville
Mallalieu
Smithdale
Little Creek
McComb
Lazy Creek
Phase 1
Soso
Davis
Heidelberg
Quitman
Phase 2
Sandersville
Eucutta
Citronelle
Future Phase
Baton Rouge
New Orleans
Houma

2005



Denbury Resources Inc.
Louisiana and Mississippi Properties

The company's CO_2 reserves at Jackson Dome are the foundation for the growth in oil production in Mississippi and Louisiana. Underlying Denbury Resources Inc. is another strong foundation of people and ideas.

LEGEND

CO_2 facility	Conventional Field
Pipeline	Tertiary Operation
Capital city	Planned Tertiary Operation

Operational Highlights

TRACY EVANS
Senior Vice President, Reservoir Engineering
Plano, Texas
Tracy joined us in 2000, and worked on the Jackson Dome acquisition. It was one of his finest hours.

RECENT ACQUISITIONS

On January 31, 2006, we completed a $248 million acquisition of three producing oil properties that we believe have up to 80 MMBbls of potential recoverable oil reserves through tertiary CO_2 flooding: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. The acquisition includes an eight-inch pipeline (currently used for natural gas storage) from our Jackson Dome area to Tinsley Field, which we plan to use to transport CO_2. We expect to begin our initial tertiary development work at Tinsley Field during 2006, with more extensive development planned for 2007. The timing of tertiary development at Citronelle Field is more uncertain as we will need to build a 60- to 70-mile pipeline extension of our CO_2 line to East Mississippi before flooding can commence. South Cypress Creek is a small field in Eastern Mississippi that will likely be developed as an additional project for our Eastern Mississippi Phase II operations, after initial development of Tinsley and Citronelle.

These three fields are currently producing approximately 2,200 BOE/d net to the acquired interests, and have proved reserves of approximately 14.4 million BOEs. We operate all three fields and own the majority of the working interests.

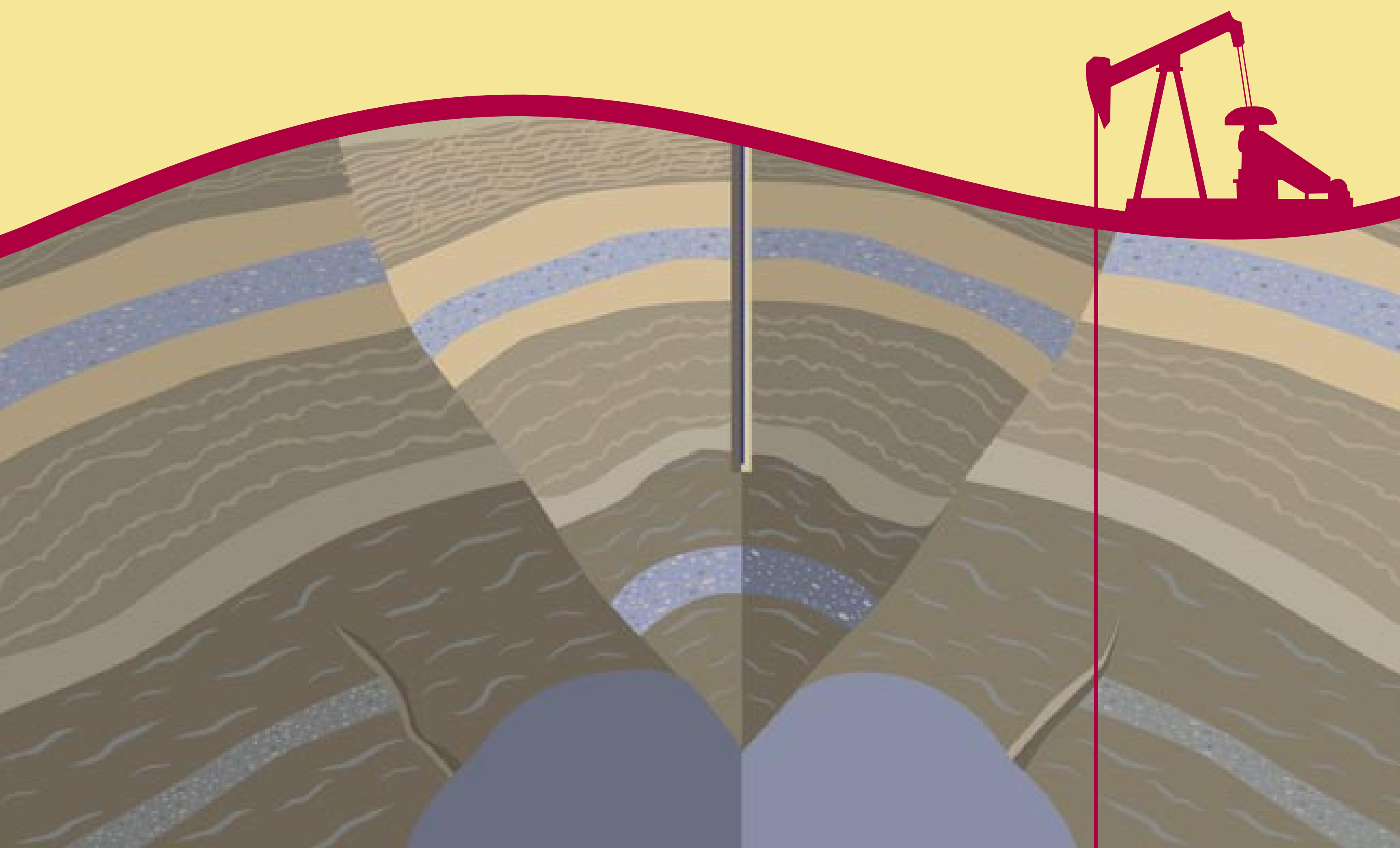
During 2005, we reached an agreement with Southern Natural Gas Company to acquire a 102-mile natural gas pipeline that runs from Gwinville Field in Central Mississippi to near the Louisiana/Mississippi border. This pipeline crosses our existing 20" CO_2 pipeline in Southwest Mississippi and will allow us to transport CO_2 to two oil fields we acquired during 2005, Cranfield and Lake St. John. These fields have historically produced from the same reservoir, the Lower Tuscaloosa, as our existing CO_2 floods in Southwest Mississippi. The purchase price and related anticipated remediation work is estimated to total approximately $5.2 million. Closing of the acquisition is subject to regulatory approval, which may take up to six months. Prior to converting the pipeline to CO_2 service, a smaller 17-mile natural gas pipeline will need to be constructed to replace natural gas service to local communities currently being serviced by the pipeline.

CO_2 TERTIARY OPERATIONS

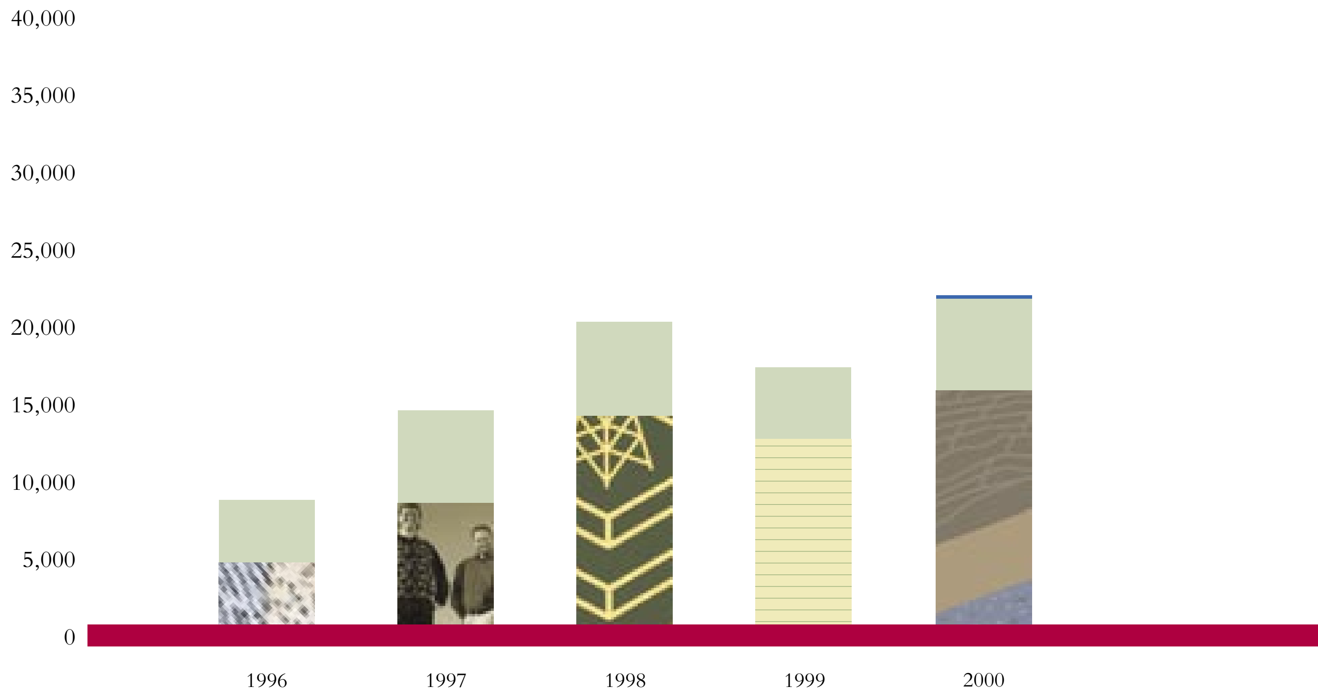
Since we acquired our first CO_2 tertiary flood in Mississippi over six years ago, we have gradually expanded our emphasis on these types of operations. We particularly like this play because of its risk profile, rate of return and lack of competition in our operating areas. During 2005, we were able to accomplish the following with regard to our tertiary operations: (i) a 74% increase in our CO_2

The People Behind the Technology
DENBURY RESOURCES INC. 2000 ANNUAL REPORT

Production and reserve growth was strong, laying the foundation for some good years to come, but the key announcement was of the acquisition of the CO_2 reserves at Jackson Dome along with the 183-mile pipeline for $42 million. This acquisition, which closed in February 2001, allowed us to outline our CO_2 strategy for the first time.

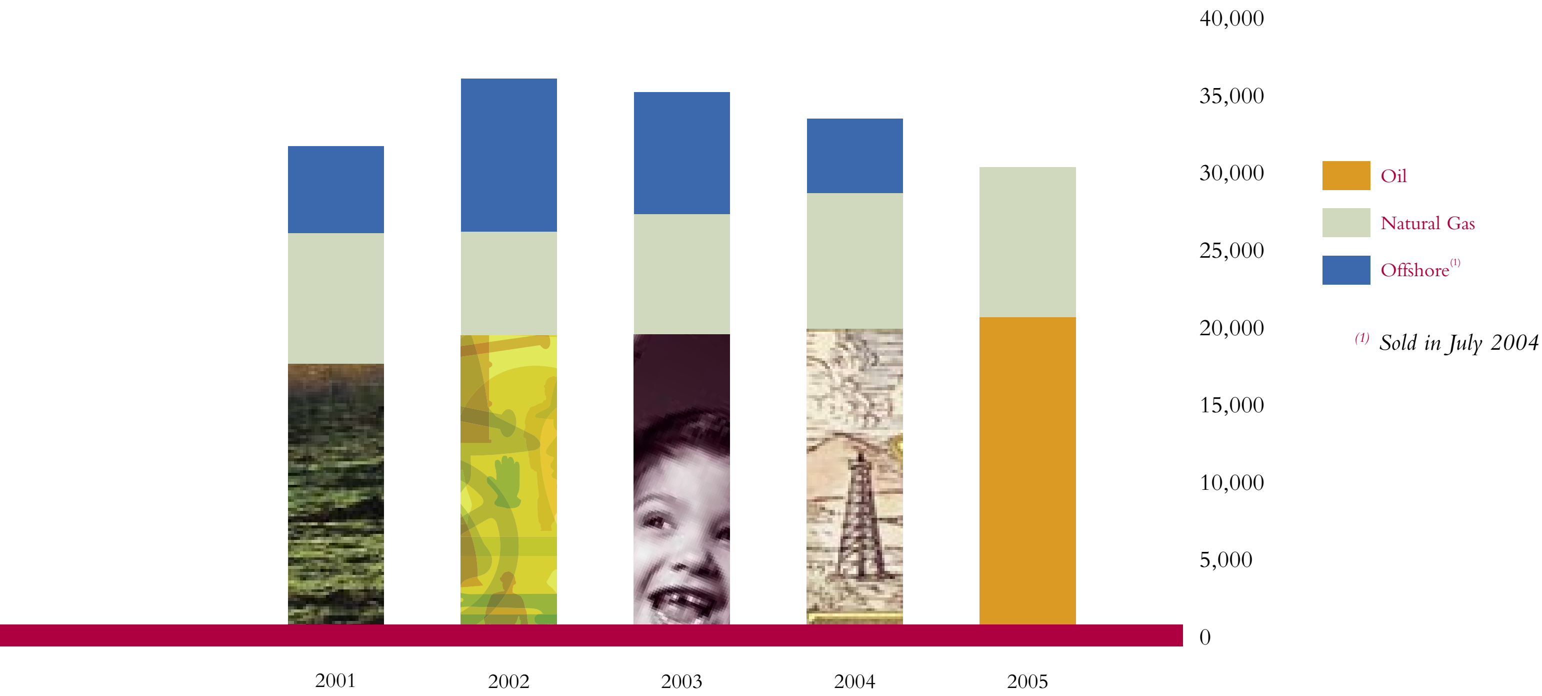


Daily Production
(BOE/d)



reserves at Jackson Dome, (ii) the completion (in February 2006) of our Free State CO_2 Pipeline to East Mississippi, (iii) the addition of two new phases of planned tertiary operations, and (iv) the continued growth in our tertiary related oil production and reserves.

We believe that having sufficient CO_2 is one of the most important ingredients, if not the key ingredient, to our tertiary operations. Since acquiring our CO_2 reserves in 2001, we have acquired two additional CO_2 source wells at Jackson Dome and drilled nine more, significantly increasing our CO_2 reserves from 800 Bcf at the time of purchase to approximately 4.6 Tcf as of December 31, 2005. We believe that this is more than enough CO_2 for our existing and currently planned phases of tertiary operations (see planned phases below). Today, we own every known producing CO_2 well in the region. As of January 2006, we estimate that we are capable of producing approximately 450 MMcf/d of CO_2, over five times the rate that we were capable of producing at the time of our initial acquisition in 2001. We continue to drill additional CO_2 wells, with three more wells planned for 2006, in order to further increase our production capacity and potentially increase our proven CO_2 reserves. Our drilling activity at Jackson Dome will continue beyond 2006, as our current forecast for the four currently planned phases suggests that we will need over 800 MMcf/d of CO_2 production by 2011. We believe that there could be another 3-4 Tcf of potential CO_2 reserves at Jackson Dome, which we also hope to add over time through further drilling, which if successful, will allow us to add additional phases of tertiary operations and recover additional oil.



We talk about our tertiary operations by labeling operating areas or groups of fields as phases. Phase I is in Southwest Mississippi, includes several oil fields along our 183-mile CO_2 pipeline that we acquired in 2001, and has been the area of our tertiary operations to date. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. Phase II, which we are just starting with the completion of our Free State CO_2 Pipeline to East Mississippi, includes Eucutta, Soso, Martinville and Heidelberg Fields. During 2005, we added two additional phases, made possible by our developing additional proven CO_2 reserves and our acquiring additional oil properties. The most significant acquired oil property is Tinsley Field, Northwest of Jackson Dome, which we label as Phase III. Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border west of the fields in Phase I. We also anticipate adding an additional phase at some point in the future at Citronelle Field, a field also recently acquired that requires a 60- to 70-mile extension to our Free State CO_2 Pipeline before tertiary operations can begin. (See regional map and phases.)

Our oil production from our CO_2 tertiary recovery activities has steadily increased during the last few years, from 3,970 Bbls/d in 2002 to 9,215 Bbls/d during 2005. During the next six years, we expect to increase our oil production from our existing fields to over 40,000 Bbls/d based on our current models for the first four phases. As of year end 2005, we had a total of 59.8 MMBbls of proved reserves attributable to our tertiary operations, 50.7 MMBbls of which

Hidden Treasure.
DENBURY RESOURCES INC. 2001 ANNUAL REPORT

In 2001, we knew we had a "Hidden Treasure" in the CO_2 play. We purchased Mallalieu Field and also 20,000 acres in the Barnett Shale.

Mallalieu Field is now our largest CO_2 flood — producing an average of 5,562 Bbls/d net to Denbury in the 4th quarter of 2005, up from 70 Bbls/d at the time of acquisition. We also acquired 20,000 acres in the Barnett Shale for approximately $2.0 million in 2001. At year end 2005, this acreage has proven reserves of 156.9 Bcf and an SEC PV-10 Value of $370.5 million.

Corporate Information

BOARD OF DIRECTORS

Ronald G. Greene
Chairman of the Board
Principal
Tortuga Investment Corp.
Calgary Alberta

David I. Heather
Director
The Scotia Group
Dallas, Texas

Greg McMichael
Independent Consultant
Denver, Colorado

Gareth Roberts
President & C.E.O.
Denbury Resources Inc.
Dallas, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Wieland F. Wettstein
President
Finex Financial
Corporation, Ltd.
Calgary Alberta

Don Wolf
President & C.E.O.
Aspect Energy
Denver, Colorado

OFFICERS

Gareth Roberts
President & C.E.O

Tracy Evans
Senior Vice President
Reservoir Engineering

Phil Rykhoek
Senior Vice President &
Chief Financial Officer

Mark Worthey
Senior Vice President
Operations

Mark Allen
Vice President & Chief
Accounting Officer

Ron Gramling
Vice President
Marketing

Ray Dubuisson
Vice President
Land

Jim Sinclair
Vice President
Exploration

CORPORATE HEADQUARTERS

Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

REGISTER AND TRANSFER AGENT

American Stock Transfer
and Trust Company
New York, NY

LEGAL COUNSEL

Jenkens & Gilchrist

BANKERS

JP Morgan (Agent)

AUDITORS

PricewaterhouseCoopers LLP

EVALUATION ENGINEERS

DeGolyer & MacNaughton

STOCK EXCHANGE

New York Stock Exchange
Trading Symbol: DNR

Annual Meeting

The annual meeting of stockholders will be held on May 10, 2006, at 3:00 P.M., local time, at the Denbury offices located at:
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024

All stockholders are encouraged to attend, but if unable should complete and return the proxy card.

For Further Information

Contact Gareth Roberts or Phil Rykhoek at the Corporate Headquarters. We have listed on our website at www.denbury.com our corporate governance guidelines, as well as the charters for our nominating/governance committee, our compensation committee, and our audit committee. The website also contains other corporate governance information such as our code of ethics for our directors, officers and employees, our hotline number to report any abnormalities, and other data.

You may contact our board members by addressing a letter to: Denbury Resources Inc. Attn: Corporate Secretary, or by e-mail to secretary@denbury.com

Our Form 10-K filed with the SEC is included herein, excluding certain exhibits. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request to Laurie Burkes at the Company's headquarters. This report can also be accessed at our website, www.denbury.com. We have included herein our Section 302 and 404 certifications by the CEO and CFO of our Form 10-K filed with the SEC.

During 2005, the Company submitted its written affirmation and annual Chief Executive Officer certification for 2004 pursuant to Section 303A of the New York Stock Exchange regulations. Such certification was qualified as the Company failed to state in its May 2005 annual meeting proxy materials that its Chairman of the Board of Directors presides at the non-management director meetings. The Company will add this disclosure to its May 2006 proxy statement.

Design by Eisenberg And Associates. Photography by Phil Hollenbeck. Printing by Williamson Printing.

were attributable to fields in Phase I with the balance in one field in Phase II. In addition to the proved reserves, we believe that there may be up to 200 MMBbls of additional potential or probable reserves that can be recovered through tertiary operations in the planned phases (including Citronelle Field).

We completed our 84-mile, 20" pipeline that runs from Jackson Dome to Eucutta Field in East Mississippi during February 2006 and began filling the line with CO_2. By April 2006, we expect to commence tertiary floods in three of our Phase II fields, Soso, Martinville and Eucutta. The pipeline was completed in about 18 months, at an estimated cost of $50 million, and is capable of transporting up to 400 MMcf/d of CO_2, although the initial six fields in Phase II will only require a peak transportation rate of around 225 MMcf/d. However, Phase II will likely expand, as there are other potential floodable fields in the East Mississippi area, plus we will likely extend the Free State CO_2 Pipeline to Citronelle Field in Southwest Alabama in order to perform tertiary flood operations at that recently acquired field.

During 2005, approximately $90.0 million was spent on capital development in Phase I, approximately $25.8 million on Phase II, approximately $46.0 million for the Free State CO_2 Pipeline, and approximately $30.9 million at Jackson Dome for wells and associated facilities. Through December 31, 2005, we have spent a total of $273.5 million on fields currently being flooded (included allocated acquisition costs), and have received $303.5 million in net operating income (revenue less operating expenses), or net positive cash flow of $30.0 million. At that date, the estimated proved oil reserves in our CO_2 fields have a PV-10 Value of $1.5 billion, using December 31, 2005 constant NYMEX pricing of $61.04 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties, but do include CO_2 source field lease operating costs and transportation costs. Through December 31, 2005, we had a balance of approximately $143.5 million of unrecovered costs for our CO_2 assets.

To date we have produced approximately 11.0 MMBbls from our CO_2 tertiary oil operations, which when included with the December 31, 2005 proved reserves, totals approximately 70 MMBbls. In addition, we believe we have identified approximately 200 MMBbls of additional potential recoverable barrels in the fields we currently own. In summary, we expect to recover approximately 80 MMBbls each from both Phase I and II, an additional 52 MMBbls from Phase III, approximately 25 MMBbls from Phase IV and approximately 26 MMBbls from Citronelle Field, a phase that is not yet scheduled. We estimate that these tertiary operations will use approximately 3.7 Tcf of our proved CO_2 reserves, while approximately 400 Bcf is dedicated to our existing industrial customers, leaving us approximately 500 Bcf for a further expansion of our program.

LAURIE BURKES
Investor Relations Manager
Plano, Texas
Since 2001, Laurie has been working to make our treasure less hidden.

GEORGE VAUGHN
Plano, Texas
1938–2006
George started working at Denbury in 1996. His contribution to our chemistry will be missed.

BARNETT SHALE

We currently own about 50,000 acres of leases in the Barnett Shale area in North Central Texas, about 20,000 acres of which is in the more tested northern area of Parker County, with the remainder in Erath and adjoining southerly counties, which are generally untested. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. Approximately $103.0 million was spent in this area during 2005, approximately $34.2 million of which related to an acquisition of additional interests in existing wells, plus significant acreage in the southern Barnett areas, with the balance primarily related to the drilling of 23 horizontal wells. As of December 31, 2005, we had approximately 157 Bcf of proved reserves in the Barnett area with a PV-10 Value of approximately $370.5 million, using December 31, 2005 Henry Hub indicative cash pricing of $10.08 per MMBtu. Through December 31, 2005, we have spent a total of $130.1 million on the Barnett Shale area and have received $35.9 million in net operating income (revenue less operating expenses), or net negative cash flow of $94.2 million.

Our production in this area increased from approximately 5.8 MMcfe/d in the fourth quarter of 2004 to approximately 18.3 MMcfe/d during the fourth quarter of 2005. We expect production in this area to grow significantly during 2006 as we plan to drill approximately 48 horizontal wells, 36 of which are scheduled for Parker County and 12 of which are scheduled for Erath and the more southern counties. Including seismic costs and pipeline infrastructure costs, our planned 2006 capital expenditures in the Barnett Shale are estimated to make up $120 million of our $494 million capital budget. We already have secured all of the drilling rigs necessary to drill and complete our planned 2006 program.

Chemistry.

DENBURY RESOURCES INC. 2002 ANNUAL REPORT

"Chemistry" was our theme in the 2002 annual report, a nice double entendre between our CO_2 play — which was working well — and the interaction with the employees, all of whom were featured in the report.

Mallalieu Works!

Great results from CO_2 flooding at Mallalieu Field in Phase I led us to plan a Phase II in East Mississippi. Phase II needed an 84-mile-long CO_2 pipeline, which was completed in early 2006 and is named the Free State CO_2 Pipeline.

A Future Full of Energy.
DENBURY RESOURCES INC. 2003 ANNUAL REPORT

By using naturally occurring carbon dioxide to recover more oil from depleted oil fields in the United States, Denbury's strategy will not only benefit current shareholders, but also create resources our children will inherit.

BARNETT SHALE

We currently own about 50,000 acres of leases in the Barnett Shale area in North Central Texas, about 20,000 acres of which is in the more tested northern area of Parker County, with the remainder in Erath and adjoining southerly counties, which are generally untested. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. Approximately $103.0 million was spent in this area during 2005, approximately $34.2 million of which related to an acquisition of additional interests in existing wells, plus significant acreage in the southern Barnett areas, with the balance primarily related to the drilling of 23 horizontal wells. As of December 31, 2005, we had approximately 157 Bcf of proved reserves in the Barnett area with a PV-10 Value of approximately $370.5 million, using December 31, 2005 Henry Hub indicative cash pricing of $10.08 per MMBtu. Through December 31, 2005, we have spent a total of $130.1 million on the Barnett Shale area and have received $35.9 million in net operating income (revenue less operating expenses), or net negative cash flow of $94.2 million.

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No sense of modesty in the 2004 Annual Report. We had sold our offshore reserves to focus on CO_2 tertiary floods onshore, Texas Pacific Group had sold their remaining interest, and we had added significant CO_2 reserves at Jackson Dome. This latter development allowed us to give the go-ahead to the Free State CO_2 Pipeline and the Phase II oil fields. For good measure, our old hedges expired and our first horizontal wells worked in the Barnett Shale, setting us up for 2005.

Winning Strategies.

DENBURY RESOURCES INC. 2004 ANNUAL REPORT

Denbury Resources is built on winning strategies that include our CO_2 play, our future development plans, strong balance sheet, and position of leverage to higher oil prices. What has brought us success in the last decade is the groundwork that will continue to bring us more success in the future.

necessary to drill and complete our planned 2006 program.

Below: Part of the illustration for our 2004 Annual Report and board game.

Contact Information

CORPORATE HEADQUARTERS

Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

FIELD OFFICES

Cleburne, TX:	T: 817.645.8100
Laurel, MS:	T: 601.428.1998
Little Creek, MS:	T: 601.276.2147
Houma, LA:	T: 504.857.9215

DATA REQUESTS

Cynthia Rodriguez

INVESTOR RELATIONS

Laurie Burkes
www.denbury.com

QUESTIONS RE: PRESS RELEASES AND STOCKHOLDER REPORTS

Gareth Roberts
President & Chief Executive Officer

Phil Rykhoek
Senior Vice President
& Chief Financial Officer

Laurie Burkes
Investor Relations Manager

ENGINEERING:	Tracy Evans, Senior Vice President, Reservoir Engineering
FINANCE:	Phil Rykhoek, Senior Vice President & Chief Financial Officer
OPERATIONS:	Mark Worthey, Senior Vice President, Operations
ACCOUNTING:	Mark Allen, Vice President & Chief Accounting Officer
MARKETING:	Ron Gramling, Vice President, Marketing
EXPLORATION:	Jim Sinclair, Vice President, Exploration
LAND:	Ray Dubuisson, Vice President, Land
LOUISIANA DIVISION:	Jeff Marcel, Houma, LA
EAST MISSISSIPPI DIVISION:	Kerry Allen, Laurel, MS
WEST MISSISSIPPI DIVISION:	Earnie Spangler, Little Creek, MS
TEXAS DIVISION:	Brent Taylor, Cleburne, TX

Cautionary Note to U.S. Investors:

The United States Securities and Exchange Commission permits oil and natural gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in the preceding section of this annual report, such as probable and potential reserves or production forecasts derived from such probable and potential reserves, that the SEC's guidelines strictly prohibit us from including in filings with the SEC.

Forward-Looking Statements:

The data contained in this annual report that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, asset values, proved reserves, potential reserves and anticipated production growth rates in our CO_2 models, production and expenditure estimates, and other enumerated reserve potential. These forward-looking statements are generally accompanied by words such as "estimated", "projected", "potential", "possible", "anticipated", "forecasted" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent 10-K and 10-Q. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

2005 FORM 10-K

(Mark One)

X Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2005
OR
___ Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ______ to ______

Commission file number 1-12935

DENBURY RESOURCES INC.

(Exact name of Registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5100 Tennyson Parkway, Suite 3000, Plano, TX	**75024**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (972) 673-2000

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

Title of Each Class:	**Name of Each Exchange on Which Registered**
Common Stock $.001 Par Value	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 X No ___

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

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 X No ___

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (See definition of "accelerated filer and large accelerated filer" in Rule 12-b2 of the Exchange Act). (Check one):
Large accelerated filer X Accelerated filer ___ Non-accelerated filer ___

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

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $2,158,311,895.

The number of shares outstanding of the registrant's Common Stock as of February 28, 2006, was 115,339,261.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	**Incorporated as to:**
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 10, 2006.	1. Part III, Items 10, 11, 12, 13, 14

Table of Contents

Glossary and Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil produced per day.
Bcf	One billion cubic feet of natural gas or CO_2.
BOE	One barrel of oil equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
CO_2	Carbon dioxide.
Finding and Development Cost	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing costs, which includes the total acquisition, exploration and development costs incurred during the period plus future development and abandonment costs related to the specified property or group of properties, by the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mbtu	One thousand Btus.
Mcf	One thousand cubic feet of natural gas or CO_2.
Mcf/d	One thousand cubic feet of natural gas or CO_2 produced per day.
MCFE	One thousand cubic feet of natural gas equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
MCFE/D	MCFEs produced per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas or CO_2.
MMCFE	One thousand MCFE.
MMCFE/D	MMCFEs produced per day.
PV-10 Value	When used with respect to oil and natural gas reserves, PV-10 Value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs and abandonment, using prices and costs in effect at the determination date, and before income taxes, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission.
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 crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.
Tcf	One trillion cubic feet of natural gas or CO_2.

* *This definition is an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X. See* **www.sec.gov/divisions/corpfin/forms/regsx.htm#gas** *for the complete definition.*

ITEM 1. BUSINESS

Website Access to Reports

We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934 available free of charge on or through our Internet website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

The Company

Denbury Resources Inc. is a Delaware corporation organized under *Delaware General Corporation Law (DGCL)* and is engaged in the acquisition, development, operation and exploration of oil and natural gas properties in the Gulf Coast region of the United States, primarily in Louisiana, Mississippi, Alabama, and Texas. Our corporate headquarters is located at 5100 Tennyson Parkway, Suite 3000, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2005, we had 460 employees, 293 of whom were employed in field operations or at the field offices. Our employee count does not include the approximately 185 employees of Genesis Energy, Inc. as of December 31, 2005, as its employees exclusively carry out the business activities of Genesis Energy, L.P., which we do not consolidate in our financial statements (see Note 1 to the Consolidated Financial Statements).

Incorporation and Organization

Denbury was originally incorporated in Canada in 1951. In 1992, we acquired all of the shares of a United States operating company, Denbury Management, Inc. (DMI), and subsequent to the merger we sold all of its Canadian assets. Since that time, all of our operations have been in the United States.

In April 1999, our stockholders approved a move of our corporate domicile from Canada to the United States as a Delaware corporation. Along with the move, our wholly owned subsidiary, DMI, was merged into the new Delaware parent company, Denbury Resources Inc. This move of domicile did not have any effect on our operations or assets.

Effective December 29, 2003, Denbury Resources Inc. changed its corporate structure to a holding company format. As part of this restructure, Denbury Resources Inc. (predecessor entity) merged into a newly formed limited liability company, and survived as, Denbury Onshore, LLC, a Delaware limited liability company and an indirect subsidiary of the newly formed holding company, Denbury Holdings, Inc. Denbury Holdings, Inc. subsequently assumed the name Denbury Resources Inc. (new entity). Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company remain publicly traded under the same symbol (DNR) on the New York Stock Exchange.

Business Strategy

As part of our corporate strategy, we believe in the following fundamental principles:

- remain focused in specific regions;
- acquire properties where we believe additional value can be created through a combination of exploitation, development, exploration and marketing, including secondary and tertiary operations;
- acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;
- maximize the value of our properties by increasing production and reserves while reducing cost; and
- maintain a highly competitive team of experienced and incentivized personnel.

Acquisitions

Information as to recent acquisitions and divestitures by Denbury is set forth under Note 2, "Acquisitions and Divestitures," to the Consolidated Financial Statements.

Oil and Gas Operations

Our CO_2 Assets

Just over six years ago, we started a new focus area through an acquisition of a carbon dioxide (CO_2) tertiary flood in an area very familiar to us, Mississippi. We have subsequently acquired other related assets and are making CO_2 flooding the largest part of our business. We particularly like this tertiary play as (i) it is lower risk and more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (generally in the twenties), and (iii) we have virtually no competition for this type of activity in our current geographic area. Generally, from East Texas to Florida, there are no known natural sources of carbon dioxide except our own, and these large volumes of CO_2 that we own drive the play. Our CO_2 reserves originated from an old underground volcano located near Jackson, Mississippi, discovered in the 1960s while companies were drilling for oil and natural gas. These CO_2 reserves are found in structural traps in the Haynesville, Buckner, Smackover and Norphlet formations at depths from 15,000 to 16,000 feet.

CO_2 injection is one of the most efficient tertiary recovery mechanisms for producing crude oil; however, because it requires large quantities of CO_2, its use has been restricted to West Texas, Mississippi and other isolated areas where large quantities of CO_2 are available. The CO_2 (in liquid form) acts as a type of solvent for the oil, causing the oil to expand and become mobile, allowing the oil to be recovered along with the CO_2 as it is produced. The CO_2 is then extracted from the oil, compressed back into a liquid state, and re-injected into the reservoir, with this recycling process occurring several times during the life of the tertiary operation. In a typical oil field up to 50% of the oil in place can be extracted during primary and secondary (waterflooding) recovery operations. Through the use of CO_2 in tertiary operations, it is possible to recover additional oil (for example, 17.5% based on historical results at Little Creek Field), almost as much oil as initially recovered during the primary production phase.

We began our CO_2 operations in August 1999, when we acquired our first CO_2 tertiary recovery project, Little Creek Field in Mississippi, a project originally developed by Shell Oil Company. Following our success at Little Creek (see "Little Creek Field" below), we embarked upon a strategic program to build a dominant position in this niche play. Following are highlights of our activities over the last few years:

- In February 2001, we acquired approximately 800 Bcf of proved producing CO_2 reserves for $42.0 million, a purchase that gave us control of most of the CO_2 supply in Mississippi, as well as ownership and control of a critical 183-mile CO_2 pipeline. This acquisition provided the platform to significantly expand our CO_2 tertiary recovery operations by assuring that CO_2 would be available to us on a reliable basis and at a reasonable and predictable cost. Since February 2001, we have acquired two wells and drilled nine additional CO_2 producing wells, significantly increasing the estimated proved CO_2 reserves to approximately 4.6 Tcf as of December 31, 2005, which is more than enough for our existing and currently planned phases of operations. The estimate of 4.6 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net ownership (net revenue interest) is approximately 3.8 Tcf and is included in the evaluation of proven CO_2 reserves prepared by DeGolyer & MacNaughton. In discussing the available CO_2 reserves, we make reference to the gross amount of proved reserves, as this is the amount that is available both for Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as Denbury is responsible for distributing the entire CO_2 production stream for both of these uses. Today, we own every producing CO_2 well in the region. Although our current proven and potential CO_2 reserves are quite large, in order to continue our tertiary development of oil fields in the area, incremental deliverability of CO_2 is needed. In order to obtain additional CO_2 deliverability, we plan to drill several additional CO_2 wells in the future, including up to three additional wells during 2006.

- During 2001 and 2002, we acquired several Mississippi oil fields in our CO_2 operating area, including Mallalieu, McComb and Brookhaven Fields (our Phase I area). Typical of mature properties in this area, the acquisition costs of these fields were relatively low in comparison to their significant reserve potential as tertiary recovery projects. As an example, we acquired West Mallalieu Field in May 2001 for $4.0 million, and by year-end 2001 had recognized 10.4 MMBOE of proved reserves, with additional future reserve potential in this field. At December 31, 2005, we had 43.2 MMBOE of proved reserves at these three fields.

- During the fourth quarter of 2005, we sold an average of 74.2 MMcf/d of CO_2 to commercial users and we used an average of 192.4 MMcf/d for our tertiary activities. We estimate that our current daily CO_2 deliverability is approximately 450 MMcf/d, and by year-end 2006 we hope to further increase our CO_2 deliverability to between 550 MMcf/d and 600 MMcf/d. We plan to continue our CO_2 drilling in 2006 and beyond, as we estimate that we will need up to 800 MMcf/d in the next five to six years in order to meet the projected timetable for our existing and currently planned tertiary projects.

- During 2004, we made the strategic decision to commence the construction of our Free State CO_2 pipeline, which runs from our CO_2 source near Jackson, Mississippi, to several of our East Mississippi properties. This pipeline is essentially complete and we expect to commence CO_2 operations in three East Mississippi fields late in the first quarter or early in the second quarter of 2006. We believe that this expansion into East Mississippi, which we call Phase II, has significant oil potential. Combined with our forecast for Phase I in Southwest Mississippi, we anticipate having significant oil production growth from our tertiary operations for several years.

- We have assigned most of our industrial contracts to Genesis during the last two years in conjunction with the sale of volumetric production payments of CO_2 to Genesis. Pursuant to the terms of the volumetric production payments, Genesis has specific maximums on the amount of CO_2 they are allowed to take each year, which generally relate to the anticipated volumes of the industrial customers. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately $0.17 per Mcf of CO_2 delivered to their industrial customers during 2005.

- In January 2006 we closed on the purchase of three oil fields for $248 million that we believe have significant potential oil reserves that can be recovered through the use of tertiary flooding: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi (our planned Phase III); Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi (see "Recently Acquired Fields" below).

- During 2005 we reached agreement with Southern Natural Gas Company to acquire a natural gas pipeline that runs from Gwinville Field to near Lake St. John Field in Louisiana. This pipeline crosses our existing 20" CO_2 pipeline in Southwest Mississippi and will allow us to transport CO_2 to Lake St. John and Cranfield Fields, both acquired in 2005 (our planned Phase IV). These fields have historically produced from the same reservoir, the Lower Tuscaloosa, as do our existing CO_2 floods in Southwest Mississippi. We are currently performing simulation studies on these fields to determine the optimum CO_2 flood to use at each field because both of these fields contain a natural gas cap, which is a different geological feature than in our other Southwest Mississippi fields. The acquisition is subject to regulatory approval, which could take up to six months.

Most of our tertiary operations are economic with oil prices in the twenties, although the precise break-even point varies by field. Our costs have escalated during the last few years and this trend is expected to continue. Our inception to date, all-in finding and development costs (including future development and abandonment costs) for our tertiary fields through December 31, 2005 was approximately $7.50 per BOE. Currently, we forecast that these costs will range from $3 to $11 per BOE, depending on the state of the field, the amount of potential oil, the proximity to a pipeline or other facilities, etc. Our operating costs averaged $12.00 per BOE in 2005 and are expected to range from $10 to $15 per BOE over the life of each field. Oil quality is another significant factor that impacts our economics. In West Mississippi, the light sweet oil produced from our tertiary operations receives near NYMEX prices, while the average discount to NYMEX for our production from oil fields in East Mississippi that we plan to flood in the near future was $9.39 per BOE during 2005, a differential that is significantly higher than historical averages, but one that appears to increase as oil prices increase. While these economic factors have wide ranges, our rate of return from these operations has been better than for our traditional oil and gas operations, and thus our tertiary operations have become our single most important focus area. While it is extremely difficult to accurately forecast future production, we believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk, and thus will be the backbone of our Company's growth for the foreseeable future.

Currently, we plan to spend approximately $45 million in 2006 in the Jackson Dome area, drilling three wells and building additional pipelines and facilities, with which we hope to add both additional CO_2 reserves and higher deliverability for future operations. Approximately $105 million in capital expenditures is budgeted in 2006 for our oil fields with tertiary operations in Southwest Mississippi and approximately $55 million for oil fields in East Mississippi, making our planned combined CO_2 and tertiary recovery related expenditures approximately 50% of our current 2006 capital budget, similar to the 53% of 2005's capital spending on these projects, including our $50 million Free State CO_2 pipeline to East Mississippi.

Our Tertiary Oil Fields with Proven Tertiary Reserves

At December 31, 2005, we had total tertiary-related proved oil reserves of approximately 59.8 MMBbls, consisting of 5.1 MMBbls at Little Creek (and surrounding smaller fields), 13.2 MMBbls at Mallalieu, 10.3 MMBbls at McComb, 19.3 MMBbls at Brookhaven, 2.9 MMBbls at Smithdale and 9.1 MMBbls at Eucutta Field. During 2006, we plan to commence tertiary operations at Eucutta, Soso and Martinville Fields, and do some preparatory work at Tinsley and Cranfield. Overall, our production from tertiary operations has increased from approximately 1,350 Bbls/d in 1999, the then existing production at Little Creek Field at the time of acquisition, to an average of 9,939 BBls/d during the fourth quarter of 2005. We expect this production to continue to increase for several years as we expand our tertiary operations to additional fields.

Little Creek Field. Little Creek Field was discovered in 1958, and by 1962 the field had been unitized and waterflooding had commenced. The pilot phase of CO_2 flooding began in 1974 and the first two phases (each in a distinct area of the field) began in 1985. When we acquired the field in 1999, the first two phases were complete and the third phase was in process. We have completed development of the third, fourth and fifth phases and most of the currently planned development work at this field, although we will continue to modify existing patterns and drill wells as necessary to recover the maximum amount of oil or to extend the field into areas that have not benefited from CO_2 injection. Based on the results of the two earliest phases of CO_2 flooding at Little Creek, tertiary recovery has increased the ultimate recovery factor in the flooded portion of the field by approximately 17.5%, as compared to recoveries of approximately 20% for primary recovery and 18% for secondary recovery. The field has produced a cumulative 16.2 MMBbls (gross) of light sweet crude as a result of tertiary operations, and we currently estimate that an additional 6.1 MMBbls (gross) can be recovered.

Production from Little Creek Field was approximately 1,350 Bbls/d when we acquired the field in 1999. During the fourth quarter of 2005, production had increased to an average of 3,210 BOE/d (including Lazy Creek). Production at Little Creek Field has most likely reached its peak and will decline over the next several years. From inception through December 31, 2005, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Little Creek (including adjoining smaller fields) of $90.4 million (at the field level), plus the fields have a PV-10 Value of $156.4 million, using a December 31, 2005, NYMEX oil price of $61.04 per Bbl and a Henry Hub indicative cash price of $10.08 per MMBtu.

Mallalieu Field. We purchased West Mallalieu Field in May 2001. Shell Oil Company unitized West Mallalieu Field and commenced a pilot project in 1986 that produced approximately 2.1 MMBbls of oil as a result of CO_2 flooding. We have expanded the pilot project by adding two to four patterns each year since 2001 and began to see our initial response approximately four months after initial injections in late 2002. We expanded our operations in this area to East Mallalieu in 2004 and 2005, with our first production response from East Mallalieu in early 2005. Production has continued to increase at these fields, from almost nothing at the time of acquisition to an average of 5,562 BBls/d in the fourth quarter of 2005. In contrast to Little Creek Field, West Mallalieu Field was not waterflooded prior to CO_2 injection. Therefore, we believe that the tertiary recovery of oil from West Mallalieu Field as a result of CO_2 injection could exceed the 17% of original oil in place that we expect from Little Creek Field. From inception through December 31, 2005, we had net positive cash flow (revenue less operating expenses and capital expenditures) from Mallalieu Field of $64.0 million (at the field level), plus the fields have a PV-10 Value of $452.3 million, using December 31, 2005, NYMEX pricing.

McComb and Smithdale Fields. We purchased McComb Field in 2002 for $2.3 million, a field with no pilot programs or tertiary operations at that time and virtually no current oil production. McComb is very close in proximity and analogous to Little Creek and Mallalieu Fields. We commenced tertiary recovery operations in 2003 and started injecting CO_2 late that year. Significant development occurred during 2004 and 2005 as we expanded the nearby Olive Field CO_2 facility to handle the processing of McComb's produced oil, water and CO_2 and developed an additional four patterns. The first production response occurred in the second quarter of 2004 and has gradually increased since that time, averaging 1,011 Bbls/d in the fourth quarter of 2005. During 2006, we expect to add six patterns within McComb Field and further expand the production facilities. In addition, we also started our initial work on an additional CO_2 flood at nearby Smithdale Field during 2004 utilizing the same CO_2 facilities. We started injecting CO_2 at Smithdale in the second quarter of 2005 and had our first production response in the fourth quarter, although the average was only 31 Bbls/d.

Brookhaven Field. Initial development of the Brookhaven Field, a field acquired from COHO Resources during 2002, began in late 2004 with the first injections of CO_2 in early 2005. During 2005, we completed development of the two patterns initiated in 2004 and developed an additional four patterns. Even though our CO_2 injections have been less than we initially planned, as we determined that some incremental work was required on the fields and the facilities and it took longer than expected, we had our first production response at Brookhaven Field in the fourth quarter of 2005, averaging 125 Bbls/d during the quarter. During 2006 we plan to expand our operations in Brookhaven and expect our production to increase at this field throughout the year.

Eucutta Field. Eucutta Field is the only field in East Mississippi that currently has proven tertiary oil reserves. This field was purchased from Amerada Hess in 1995 and is analogous to Heidelberg Field in that the majority of its historical production was produced from the Eutaw formation. Eucutta was unitized for water flooding in 1966 and has gone through several stages of development. During the 1980s, Amerada Hess installed an inverted 5-spot pilot test in the City Bank sand (one of the Eutaw sands) to test the application of CO_2 flooding. Although the pilot test only covered approximately 20 acres, the pilot test was successful in recovering an additional 17% of the original oil in place within the pattern. Based on this success, we have designed a CO_2 project for the Eucutta Field, began construction of our CO_2 facilities and began initial well work during 2005. Initial injection of CO_2 is projected to commence late in the first quarter of 2006. Our plans for 2006 include the development of an additional 21 of the 48 total patterns and expansion of our CO_2 facilities. During 2005 we recognized 9.1 MMBbls of proved reserves in the Eucutta field attributable to the CO_2 flood. The 9.1 MMBbls represents a lower recovery factor than was achieved in the pilot program in the 1980s and therefore we expect to have upward reserve increases in the future.

Through December 31, 2005, we have spent a total of $273.5 million on tertiary oil fields (including the allocated acquisition costs), and have received $303.5 million in net operating income (revenue less operating expenses), or net positive cash flow of $30.0 million. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties at Jackson Dome, which had a net unrecovered cost balance of $143.5 million as of December 31, 2005, including $46.9 million associated with the Free State CO_2 pipeline. At year-end 2005, the proved oil reserves in our CO_2 fields had a PV-10 Value of $1.5 billion, using December 31, 2005, NYMEX pricing of $61.04 per Bbl.

East Mississippi Fields Without Proven Tertiary Oil Reserves

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest producer in the basin. For years, this has been our area with the highest production and most proved reserves, representing production of approximately 11,475 BOE/d during the fourth quarter of 2005 (36% of our Company total) and proved reserves of 54.5 MMBOE as of December 31, 2005 (36% of our Company total). Since we have generally owned these Eastern Mississippi properties longer than properties in our other regions, they tend to be more fully developed, and although most are targeted for tertiary operations in the future, we plan to commence tertiary operations in three of these fields in early 2006. Production from these fields has declined slightly over the last three years, averaging 13,638 BOE/d in 2003, 13,085 BOE/d in 2004 and 12,072 BOE/d during 2005. For 2006, we expect our budget in this region for conventional operations to be around $50 million, about the same as in 2005, representing approximately 10% of our current 2006 exploration and development budget of $494 million.

Heidelberg Field. The largest field in the region, and our largest field corporately, is Heidelberg Field, which for the fourth quarter of 2005 produced an average of 6,945 BOE/d, 11% less than the 2004 average of 7,775 BOE/d. Heidelberg

Field was acquired from Chevron in December 1997. This field was discovered in 1944 and has produced an estimated 212 MMBbls of oil and 65 Bcf of gas since its discovery. The field is a large salt-cored anticline that is divided into western and eastern segments due to subsequent faulting. There are 11 producing formations in Heidelberg Field containing 40 individual reservoirs, with the majority of the past and current production coming from the Eutaw, Selma Chalk and Christmas sands at depths of 3,500 to 5,000 feet. When we acquired the property in 1997, production was approximately 2,800 BOE/d.

The primary oil production at Heidelberg is from five waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). Most of our recent development at Heidelberg has been in the Selma Chalk, a natural gas reservoir at around 3,700 feet, making Heidelberg our second largest gas field. We have steadily developed the Selma Chalk since 2001, drilling from 13 to 27 wells per year, increasing the natural gas production at Heidelberg to a peak quarterly average of 15.8 MMcf/d in the fourth quarter of 2004, and an average of 14.1 MMcf/d for 2005. During 2005 we drilled and completed our first horizontal well in the Selma Chalk. The well was drilled in an area of the field where prior vertical wells typically produced lower than average production rates. The well was completed in two stages and the initial results have been very encouraging. We will most likely convert a significant number of our planned wells in 2006 to horizontal wells. If the early results are sustainable, then horizontal drilling may allow us to develop areas of the Selma Chalk that were previously thought to be uneconomic. Currently, we plan to drill 27 vertical natural gas wells during 2006, although the number of wells will likely be reduced if vertical wells are converted to horizontal wells.

Soso Field. Soso Field was purchased from COHO Resources in 2002. Although this field produces from numerous sands, the majority of our work in 2005 involved the construction of CO_2 facilities and establishment of two patterns in the Bailey sand. This field has not had any previous CO_2 injection or pilot projects. In reviewing Soso Field, we studied the Bailey sand, which has been one of the more prolific reservoirs within the field and exhibits characteristics of a depletion drive reservoir. Because of similar reservoir characteristics to our West Mississippi floods, we expect the Bailey tertiary flood to perform in a similar manner. Our original plans called for the co-development of the Cotton Valley and Bailey sands. After further review during 2005, we concluded that co-development of the Rodessa (a larger potential reserve target) could be done with minimal changes to our overall plan. Therefore, during 2006 we plan on initiating our first injections of CO_2 by developing four additional Bailey patterns and one Rodessa pattern.

Martinville Field. Martinville field was purchased from COHO Resources in 2002. As is the case with all of the East Mississippi fields, Martinville produces from multiple reservoirs. Unlike the majority of our other planned CO_2 projects, Martinville does not contain one very large reservoir to CO_2 flood, but rather several smaller reservoirs. We have identified three formations at Martinville in which we plan to initiate CO_2 flooding. The first reservoir to be CO_2 flooded is the Mooringsport, which, because it has been waterflooded very successfully, is expected to CO_2 flood successfully as well. We began construction of the required CO_2 facilities and essentially completed the development of the Mooringsport sand during 2005. The second reservoir, the Rodessa, has similar reservoir characteristics to the Mooringsport. We expect to initiate injection into the Rodessa with the completion of one injector well during 2006. The final reservoir is the Wash Fred 8500' reservoir. This reservoir contains a low oil gravity, 15 API, which will not develop miscibility with CO_2 at reservoir conditions. Denbury has several fields with similar gravity oils, which like the Wash Fred 8500' have had lower recoveries due to the low oil gravities and strong water drives which do not sweep the oil efficiently. We plan to initiate injection during the first quarter into the Wash Fred 8500' reservoir at the crest of the structure, allow the CO_2 to swell the oil, decrease the oil viscosity, and displace the water and oil downward in the reservoir to the producing wells. Successful implementation of a CO_2 project in the Wash Fred 8500' reservoir would provide the impetus to look at a whole new set of fields that have historically not been considered for CO_2 injection, although there can be no assurance that this technique will be successful or economic. We anticipate that our first injections of CO_2 in Martinville will commence late in the first quarter of 2006.

Recently Acquired Mississippi Fields

January 2006 Acquisition. In January 2006, we closed on the purchase of three old oil fields for $248 million that we believe have significant potential oil reserves that can be recovered through the use of tertiary flooding: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi, Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. The acquisition includes an eight-inch pipeline (currently being used for natural gas storage) from our Jackson Dome area to Tinsley Field. We plan to initially use this pipeline to transport CO_2 to Tinsley Field. We anticipate commencing initial tertiary development work at Tinsley Field in 2006, with more extensive development planned for 2007.

In order to transport CO_2 to Citronelle Field in Alabama, a 60- to 70-mile extension will need to be added to our nearly completed Free State CO_2 pipeline between Jackson Dome and our Eastern Mississippi Eucutta Field. We are still reviewing Citronelle Field and have not yet determined a definitive timetable for tertiary development of Citronelle.

South Cypress Creek is a small field in Eastern Mississippi and will likely be developed after initial development of the Tinsley and Citronelle Fields as an additional project for the our Eastern Mississippi Phase II CO_2 project.

These three fields are currently producing approximately 2,200 BOE/d net to the acquired interests, and have proved reserves of approximately 14.4 million BOEs. We operate all three fields and own the majority of the working interests.

Texas and the Barnett Shale

We currently own about 50,000 acres of leases in the Barnett Shale area in North Central Texas, about 20,000 acres of which is in the more tested northern area of Parker County, with the remainder in Erath and adjoining more southern and untested counties. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. As of December 31, 2005, we had approximately 157 Bcf of proved reserves in the Barnett with a PV-10 Value of approximately $370.5 million, using December 31, 2005, Henry Hub indicative cash pricing of $10.08 per MMBtu. Through December 31, 2005, we have spent a total of $130.1 million on the Barnett Shale area and have received $35.9 million in net operating income (revenue less operating expenses), or net negative cash flow of $94.2 million.

We have continued to refine our completion and fracturing techniques, including an analysis of the best number of fracture treatments to adequately stimulate the entire length of the lateral sections of our horizontal wells, which can exceed 4,000 feet. During 2005 we drilled and completed an additional 23 horizontal wells, increasing our net Barnett Shale production from approximately 5.8 MMcfe/d in the fourth quarter of 2004 to approximately 18.3 MMcfe/d during the fourth quarter of 2005. During 2005, we also shot 3-D seismic data over our entire northern acreage position, 90 to 100 square miles and initiated a shoot of the southern acreage. The 3-D seismic data should allow us to better locate our wells so that we encounter less faulting and underground sink holes, which have been associated with fracture stimulations into zones outside of the Barnett Shale that are typically water bearing. We expect production in this area to grow significantly during 2006 as we plan to drill approximately 48 horizontal wells, 36 of which are scheduled for Parker County and 12 of which are scheduled for Erath and the more southern counties. Including seismic costs and pipeline infrastructure costs, our planned 2006 capital expenditures in the Barnett Shale are estimated to make up $120 million of our $494 million capital budget. We already have secured all of the drilling rigs necessary to drill and complete our planned 2006 program.

With the continued expansion of the Barnett Shale play by others into other areas of North Central Texas, we have purchased approximately 30,000 acres in Erath, Bosque, Hamilton and Hill counties. We expect to commence the drilling of our first horizontal well in this area in the first or second quarter of 2006. This area of the Barnett shale does not possess the overall gross thickness that our wells in Parker County possess, but may contain the same net productive thickness. Until we have drilled a few of our own wells in this area, we are not sure how the economics will compare to the Parker County acreage.

We are continuing to review the issue of pipeline capacity in our area of the Barnett Shale play. Several gas buyers and pipeline companies are entering the area and making plans to install additional pipelines to handle the anticipated future volumes of gas and we are in various stages of negotiations regarding transportation.

South Louisiana

We own interests in the land and marshes of south Louisiana, a region that produces primarily natural gas. Production from this area averaged 42.0 MMcfe/d net to our interest in the fourth quarter of 2005, a decrease from our 2004 average of 45.8 MMcfe/d, but an increase from earlier 2005 quarters as a result of new wells drilled during 2005. During 2005, we spent approximately $47.4 million (excluding acquisitions) in this region, approximately 16% of our total exploration and development expenditures, drilling approximately 16 wells, primarily in Cameron, Jefferson Davis, and Terrebonne Parish areas. For 2006, our spending is expected to be about the same, with a budget of $50 million, or 10% of our currently planned $494 million exploration and development budget.

The majority of our onshore Louisiana fields lie in the Houma embayment area of Terrebonne Parish, including Lirette, and South Chauvin Fields, and our recent shallow natural gas plays at Bayou Sauveur and Gibson Fields. We drilled 12 wells in Terrebonne Parish during 2005, all of which were successful. In 2006, we plan to drill approximately six exploratory wells in Terrebonne Parish and one development well.

In late 2004, we participated in the drilling of a prospect in South Chauvin Field that was based on 3-D seismic amplitudes that could be tied to past production. The first well was successfully drilled and tested in late 2004. During 2005, we participated in the drilling of three additional wells that tested similar amplitudes in the overall prospect. All three were successful. Based on our current production history and geological information, it appears these amplitudes are not in communication with each other and that each well is producing from its own reservoir. Gross production rates from these wells have individually exceeded 13 MMcf/d and the proved reserves (gross) associated with each well range from 1.5 Bcf to 5 Bcf. We have an average working interest of approximately 37.5% in these wells and prospects. Based on the proved reserves, the production life of each well will be short, most likely between 2 and 3 years. Our current plans include the drilling of 2 to 3 additional wells during 2006 in this prospect area testing additional amplitudes.

In late 2005 we spudded our Gumbo Prospect, the Westerfelt #2 well, a 19,000+ foot well testing the Rob L sands. The prospect was developed by merging three 3-D data sets that essentially all intersected over the project, but could not be fully imaged on any one dataset. We logged the well in January 2006 and expect to have this well completed in the first half of 2006. Based on the logs and initial seismic interpretation, we have preliminarily estimated that the well has proved reserves of approximately 12 Bcfe net to our 29% net revenue interest. The total hydrocarbon column and the associated potential reserves could be several times greater than our preliminary estimate of proved reserves if the reservoir is filled to the spill point of the structure. The drilling of delineation wells and or significant production history will be required to fully evaluate the potential reserves associated with this prospect. A second well on this prospect will likely be drilled in 2006, although the exact timing is unknown at this point.

Another of our significant South Louisiana fields, Thornwell Field, has historically been characterized by short-lived natural gas properties that have high initial production rates with a good rate of return. During 2005 we drilled one exploratory well to test the Marg Tex/Bol Mex sands and one development well in the Bol Perc. Although both wells were successful, the Marg Tex well, Pettitjean 8-1, encountered a significant amount of net pay. Currently the well is producing at a gross rate of 13 MMcf/d and 375 Bbls/d (7 MMcfe/d net to us). Based on the Pettitjean 8-1's performance, we believe that three to four additional locations will be required to fully develop the potential reserves associated with the entire prospect. During 2006 we plan to drill at least two of these wells.

Field Summaries

Denbury operates in four primary areas: Louisiana, Eastern Mississippi, Western Mississippi and Texas. Our 13 largest fields (listed below) constitute approximately 91% of our total proved reserves on a BOE basis and 90% on a PV-10 Value basis. Within these 13 fields, we own a weighted average 94% working interest and operate all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve and allows us to effectively manage the properties from our three primary field offices in Houma, Louisiana, Laurel, Mississippi, and Cleburne, Texas.

	PROVED RESERVES AS OF DECEMBER 31, 2005[1]					2005 AVERAGE DAILY PRODUCTION		
	OIL (MBbls)	GAS (MMcf)	MBOEs	BOE % OF TOTAL	PV-10 VALUE (000'S)	OIL (Bbls/d)	NATURAL GAS (Mcf/d)	AVERAGE NET REVENUE INTEREST
MISSISSIPPI – CO_2 FLOODS								
Brookhaven	19,273	—	19,273	12.6%	$ 405,761	31	—	81.9%
Mallalieu (East & West)	13,164	—	13,164	8.6%	452,306	4,739	—	76.6%
McComb/Olive	10,268	—	10,268	6.7%	277,894	908	—	75.6%
Little Creek & Lazy Creek	5,103	—	5,103	3.4%	156,377	3,529	—	83.3%
Smithdale	2,890	—	2,890	1.9%	68,345	8	—	79.5%
Eucutta	9,110	—	9,110	6.0%	102,427	—	—	82.8%
Total Mississippi – CO_2 floods	59,808	—	59,808	39.2%	1,463,110	9,215	—	79.7%
OTHER MISSISSIPPI								
Heidelberg (East & West)	29,077	54,784	38,208	25.0%	636,856	4,957	14,133	75.9%
Eucutta	4,368	—	4,368	2.9%	74,810	986	47	81.4%
King Bee	1,792	—	1,792	1.2%	29,937	377	—	79.4%
Other Mississippi	8,195	11,898	10,178	6.7%	188,067	2,867	3,130	38.0%
Total Other Mississippi	43,432	66,682	54,546	35.8%	929,670	9,187	17,310	64.3%
LOUISIANA								
Thornwell	1,206	13,049	3,381	2.2%	132,482	377	4,838	40.4%
S. Chauvin	501	15,581	3,098	2.0%	112,859	241	6,963	36.1%
Lirette	85	7,861	1,395	0.9%	59,978	193	7,002	67.8%
Other Louisiana	1,027	16,426	3,765	2.5%	137,103	771	8,687	35.5%
Total Louisiana	2,819	52,917	11,639	7.6%	442,422	1,582	27,490	39.3%
TEXAS								
Newark (Barnett Shale)	—	156,858	26,143	17.1%	370,535	5	12,844	74.3%
OTHER	114	1,910	432	0.3%	9,741	24	1,052	0.6%
COMPANY TOTAL	106,173	278,367	152,568	100.0%	$ 3,215,478	20,013	58,696	52.4%

(1) *The reserves were prepared using constant prices and costs in accordance with the guidelines of the SEC based on the prices received on a field-by-field basis as of December 31, 2005. The prices at that date were a NYMEX oil price of $61.04 per Bbl adjusted to prices received by field and a Henry Hub natural gas price average of $10.08 per MMBtu also adjusted to prices received by field.*

Oil and Gas Acreage, Productive Wells, and Drilling Activity

In the data below, "gross" represents the total acres or wells in which we own a working interest and "net" represents the gross acres or wells multiplied by Denbury's working interest percentage. For the wells that produce both oil and gas, the well is typically classified as an oil well or gas well based on the ratio of oil to gas production.

Oil and Gas Acreage

The following table sets forth Denbury's acreage position at December 31, 2005:

	DEVELOPED		UNDEVELOPED		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Louisiana	**40,002**	**33,721**	**28,263**	**19,928**	**68,265**	**53,649**
Mississippi	**97,430**	**77,918**	**256,221**	**41,787**	**353,651**	**119,705**
Texas	**16,543**	**14,612**	**53,194**	**35,089**	**69,737**	**49,701**
Other	**17,239**	**7,635**	**83,202**	**12,352**	**100,441**	**19,987**
Total	**171,214**	**133,886**	**420,880**	**109,156**	**592,094**	**243,042**

Denbury's net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 4% in 2006, 22% in 2007 and 21% in 2008.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells at December 31, 2005:

	PRODUCING OIL WELLS		PRODUCING NATURAL GAS WELLS		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
OPERATED WELLS:						
Louisiana	**23**	**17.1**	**49**	**41.8**	**72**	**58.9**
Mississippi	**437**	**420.7**	**169**	**155.7**	**606**	**576.4**
Texas	**—**	**—**	**67**	**65.5**	**67**	**65.5**
Other	**1**	**0.5**	**30**	**16.8**	**31**	**17.3**
Total	**461**	**438.3**	**315**	**279.8**	**776**	**718.1**
NON-OPERATED WELLS:						
Louisiana	**12**	**1.1**	**21**	**4.7**	**33**	**5.8**
Mississippi	**32**	**1.7**	**16**	**3.9**	**48**	**5.6**
Texas	**—**	**—**	**2**	**0.2**	**2**	**0.2**
Other	**2**	**—**	**1**	**0.7**	**3**	**0.7**
Total	**46**	**2.8**	**40**	**9.5**	**86**	**12.3**
TOTAL WELLS:						
Louisiana	**35**	**18.2**	**70**	**46.5**	**105**	**64.7**
Mississippi	**469**	**422.4**	**185**	**159.6**	**654**	**582.0**
Texas	**—**	**—**	**69**	**65.7**	**69**	**65.7**
Other	**3**	**0.5**	**31**	**17.5**	**34**	**18.0**
Total	**507**	**441.1**	**355**	**289.3**	**862**	**730.4**

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years:

	YEAR ENDED DECEMBER 31,					
	2005		2004		2003	
	GROSS	NET	GROSS	NET	GROSS	NET
EXPLORATORY WELLS:[1]						
Productive[2]	**12**	**7.1**	8	5.8	7	5.3
Non-productive[3]	**1**	**0.6**	4	2.3	7	4.8
DEVELOPMENT WELLS:[1]						
Productive[2]	**81**	**74.3**	68	53.8	37	31.3
Non-productive[3][4]	**—**	**—**	1	0.6	3	1.2
Total	**94**	**82.0**	81	62.5	54	42.6

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered oil or gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A developmental well is a well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(3) A nonproductive well is an exploratory or development well that is not a producing well.

(4) During 2005, 2004 and 2003, an additional 5, 8, and 5 wells, respectively, were drilled for water or CO_2 injection purposes.

Production and Unit Prices

Information regarding average production rates, unit sale prices and unit costs per BOE are set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Income" included herein.

Title to Properties

Customarily in the oil and gas industry, only a perfunctory title examination is conducted at the time properties believed to be suitable for drilling operations are first acquired. Prior to commencement of drilling operations, a thorough drill site title examination is normally conducted, and curative work is performed with respect to significant defects. During acquisitions, title reviews are performed on all properties; however, formal title opinions are obtained on only the higher value properties. We believe that we have good title to our oil and natural gas properties, some of which are subject to minor encumbrances, easements and restrictions.

Geographic Segments

All of our operations are in the United States.

Significant Oil and Gas Purchasers and Product Marketing

Oil and gas sales are made on a day-to-day basis under short-term contracts at the current area market price. The loss of any single purchaser would not be expected to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive. For the year ended December 31, 2005, we had three purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%), Hunt Crude Oil Supply Co. (20%) and Sunoco, Inc. (13%). For the year ended December 31, 2004, two purchasers each accounted for more than 10% of our total oil and natural gas revenues: Hunt Crude Oil Supply Co. (21%) and Genesis Energy, L.P. (14%). For the year ended December 31, 2003, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Crude Oil Supply Co. (15%) and Genesis Energy, L.P. (12%).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our gas production to pipelines, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. Our production is primarily from developed fields close to major pipelines or refineries and established infrastructure. As a result, we have not experienced any difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

The quality of our crude oil varies by area as well as the corresponding price received. In Heidelberg Field, our single largest field, and our other Eastern Mississippi properties, our oil production is primarily light to medium sour crude and sells at a significant discount to the NYMEX prices. In Western Mississippi, the location of our current CO_2 operations, our oil production is primarily light sweet crude, which typically sells at near NYMEX prices, or often at a premium. For the year ended December 31, 2005, the discount for our oil production from Heidelberg Field averaged $13.98 per Bbl and for our Eastern Mississippi properties as a whole the discount averaged $13.23 per Bbl relative to NYMEX oil prices. For Mallalieu Field, the largest producer during 2005 of our CO_2 properties in Western Mississippi, we averaged a premium of $0.78 per Bbl over NYMEX oil prices, and $0.60 per Bbl over NYMEX prices for our tertiary oil production in Western Mississippi taken as a whole. Our Louisiana properties averaged $6.15 per Bbl below NYMEX prices during 2005.

Natural Gas Marketing

Virtually all of our natural gas production is close to existing pipelines and consequently we generally have a variety of options to market our natural gas. We sell the majority of our natural gas on one-year contracts with prices fluctuating month-to-month based on published pipeline indices with slight premiums or discounts to the index. We receive near NYMEX or Henry Hub prices for most of our natural gas sales due to our proximity to Henry Hub and the high Btu content of our natural gas. For the year ended December 31, 2005, we averaged $0.07 above NYMEX for our Louisiana natural gas production. However, in the Barnett Shale area in Texas, due primarily to its location, the price we received averaged $1.82 below NYMEX. We expect our overall differential to NYMEX to gradually increase in the future due to our increasing emphasis in the Barnett Shale area.

Competition and Markets

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available funds, available information about prospective properties and our standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gas gathering systems. Competition is also presented by alternative fuel sources, including heating oil and other fossil fuels. Because of the long-lived, high margin nature of our oil and gas reserves and management's experience and expertise in exploiting these reserves, we believe that we are effective in competing in the market.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We cannot be certain when we will experience these issues and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results or restrict our ability to drill those wells and conduct those operations that we currently have planned and budgeted.

Federal and State Regulations

Numerous federal and state laws and regulations govern the oil and gas industry. These laws and regulations are often changed in response to changes in the political or economic environment. Compliance with this evolving regulatory burden is often difficult and costly, and substantial penalties may be incurred for noncompliance. The following section describes some specific laws and regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Management believes that we are in substantial compliance with all laws and regulations applicable to our operations and that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital costs of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements. However, management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of operations.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in those units and the unitization or pooling of oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability.

Federal Regulation of Sales Prices and Transportation

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the U.S. federal government and are affected by the availability, terms and cost of transportation. In particular, the price and terms of access to pipeline transportation are subject to extensive U.S. federal and state regulation. The Federal Energy Regulatory Commission (FERC) is continually proposing and implementing new rules and regulations affecting the natural gas industry. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. The ultimate impact of the complex rules and regulations issued by FERC cannot be predicted. Some of FERC's proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. While our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation, our ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation. Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective and their effect, if any, on our operations. Historically, the natural gas industry has been heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC, Congress and the states will continue indefinitely into the future.

Natural Gas Gathering Regulations

State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Federal, State or Indian Leases

Our operations on federal, state or Indian oil and 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 (MMS) and other agencies.

Environmental Regulations

Public interest in the protection of the environment has increased dramatically in recent years. Our oil and natural gas production and saltwater disposal operations and our processing, handling and disposal of hazardous materials such as hydrocarbons and naturally occurring radioactive materials are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of hazardous material, third-party claims for property damage and personal injuries, fines and sanctions, as a result of any violations or liabilities under environmental or other laws. Changes in or more stringent enforcement of environmental laws could also result in additional operating costs and capital expenditures.

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 gas exploration, development and production operations, and consequently may impact the Company's operations and costs. These regulations include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act, Federal Resource Conservation and Recovery Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements, which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company; (iv) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; and (vi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material (NORM).

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 management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows.

Estimated Net Quantities of Proved Oil and Gas Reserves and Present Value of Estimated Future Net Revenues

DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas, prepared estimates of our net proved oil and natural gas reserves as of December 31, 2005, 2004 and 2003. The reserve estimates were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission (SEC). The prices used in preparation of the reserve estimates were based on the market prices in effect as of December 31 of each year, with the appropriate adjustments (transportation, gravity, basic sediment and water ("BS&W"), purchasers' bonuses, Btu, etc.) applied to each field. The reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interests in our properties.

Our proved nonproducing reserves primarily relate to reserves that are to be recovered from productive zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties typically have both proved producing and proved nonproducing reserves.

Proved undeveloped reserves associated with our CO_2 tertiary operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 97% of our proved undeveloped oil reserves. We consider these reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production because all of these proved undeveloped reserves are associated with secondary recovery or tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production. The main reason these reserves are classified as undeveloped is because they require significant additional capital associated with drilling/re-entering wells or additional facilities in order to produce the reserves and/or are waiting for a production response to the water or CO_2 injections.

Our proved undeveloped natural gas reserves associated with our Selma Chalk play at Heidelberg and the Barnett Shale play account for approximately 95% of our proved undeveloped natural gas reserves. The remaining undeveloped natural gas reserves are spread over multiple fields. Our current plans for 2006 include development of 70 to 80 wells in our two primary natural gas plays, the Barnett Shale and Selma Chalk.

	DECEMBER 31,		
	2005	2004	2003
ESTIMATED PROVED RESERVES:			
Oil (MBbls)	**106,173**	101,287	91,266
Natural gas (MMcf)	**278,367**	168,484	221,887
Oil equivalent (MBOE)	**152,568**	129,369	128,247
PERCENTAGE OF TOTAL MBOE:			
Proved producing	**40%**	39%	43%
Proved non-producing	**16%**	16%	18%
Proved undeveloped	**44%**	45%	39%
REPRESENTATIVE OIL AND GAS PRICES:(1)			
Oil – NYMEX	**$ 61.04**	$ 43.45	$ 32.52
Natural gas – Henry Hub	**10.08**	6.18	5.97
PRESENT VALUES:(2)			
Discounted estimated future net cash flow before income taxes ("PV-10 Value") (thousands)	**$3,215,478**	$1,643,289	$1,566,371
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	**2,084,449**	1,129,196	1,124,127

(1) *The prices of each year-end were based on market prices in effect as of December 31 of each year, NYMEX prices per Bbl and Henry Hub cash prices per MMBtu, with the appropriate adjustments (transportation, gravity, BS&W, purchasers' bonuses, Btu, etc.) applied to each field to arrive at the appropriate corporate net price.*

(2) *Determined based on year-end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum.*

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. See "Risk Factors – Estimating our reserves, production and future net cash flow is difficult to do with any certainty." See also Note 13, "Supplemental Oil and Natural Gas Disclosures," to the Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

Risks Related To Our Business

Our production will decline if our access to sufficient amounts of carbon dioxide is limited.

Our current long-term growth strategy is focused on our CO_2 tertiary recovery operations, and we expect approximately 50% of our 2006 capital expenditures to be in this area. The crude oil production from our tertiary recovery projects depends on having access to sufficient amounts of carbon dioxide. Our ability to produce this oil would be hindered if our supply of carbon dioxide were limited due to problems with our current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Our anticipated future crude oil production is also dependent on our ability to increase the production volumes of CO_2. If our crude oil production were to decline, it could have a material adverse effect on our financial condition and results of operations and cash flows.

Oil and natural gas prices are volatile.
A substantial decrease in oil and natural gas prices could adversely affect our financial results.

Our future financial condition, results of operations and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future, especially given current world geopolitical conditions. Our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. This price volatility also affects the amount of our cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow or have outstanding under our bank credit facility is subject to semi-annual redeterminations. Oil prices are likely to affect us more than natural gas prices because approximately 70% of our proved reserves are oil. The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign oil and natural gas;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico;
- market uncertainty;
- political conditions in oil and natural gas producing regions, including the Middle East; and
- worldwide economic conditions.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements with any certainty. Also, oil and natural gas prices do not necessarily move in tandem. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect upon our financial condition, results of operations, oil and natural gas reserves and the carrying values of our oil and natural gas properties. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations or make planned expenditures.

Since the end of 1998, oil prices have gone from near historic low prices to historic highs. At the end of 1998, NYMEX oil prices were at historic lows of approximately $12.00 per Bbl, but have generally increased since that time, albeit with fluctuations. For 2005, NYMEX oil prices were high throughout the year, averaging over $56.00 per Bbl for 2005. During 2004 and 2005, the price we received for our heavier, sour crude oil did not correlate as well with NYMEX prices as it has historically. During 2002 and 2003, our average discount to NYMEX was $3.73 per Bbl and $3.60 per Bbl respectively.

During 2004, this differential increased to $4.91 per Bbl for the year as a result of the price deterioration for heavier, sour crudes, and was even higher during the fourth quarter of 2004, averaging $6.48 per Bbl. During 2005, our oil differential averaged $6.33 per Bbl. While we attempt to obtain the best price for our crude in our marketing efforts, we cannot control these market price swings and are subject to the market volatility for this type of oil. These price differentials relative to NYMEX prices can have as much of an impact on our profitability as does the volatility in the NYMEX oil prices.

Natural gas prices have also experienced volatility during the last few years. During 1999 natural gas prices averaged approximately $2.35 per Mcf and, like crude oil, have generally trended upward since that time, although with significant fluctuations along the way. During 2004 NYMEX natural gas prices averaged $6.23 per MMBtu and in 2005, averaged $8.97 per MMBtu.

Product Price Derivative Contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we currently and may in the future enter into derivative contracts in order to economically hedge a portion of our oil and natural gas production. Derivative contracts expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counter-party to the derivative contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these derivative contracts may limit the benefit we would receive from increases in the prices for oil and natural gas. Information as to these activities is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management," and in Note 9, "Derivative Contracts," to the Consolidated Financial Statements.

Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Due to the recent record high oil and gas prices, we have experienced shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services and personnel in our exploration and production operations. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results or restrict or delay our ability to drill those wells and conduct those operations that we currently have planned and budgeted.

Our future performance depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we can successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We have historically replaced reserves through both drilling and acquisitions. In the future we may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investment to maintain or expand our oil and natural gas reserves if our cash flows from operations are reduced, due to lower oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. Further, the process of using CO_2 for tertiary recovery and the related infrastructure requires significant capital investment, often one to two years prior to any resulting production and cash flows from these projects, heightening potential capital constraints. If we do not continue to make significant capital expenditures, or if outside capital resources become limited, we may not be able to maintain our growth rate. In addition, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be encountered. Exploratory drilling involves more risk than development drilling because exploratory drilling is designed to test formations for which proved reserves have not been discovered.

In January 2006, we purchased three oil fields for $248 million that we believe have significant potential oil reserves that can be recovered through the use of tertiary flooding: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near our Eucutta Field in Eastern Mississippi. These three fields are producing approximately 2,200 BOE/d net to the acquired interests, and have proved reserves of approximately 14.4 million BOEs. If we are unable to successfully develop the potential oil reserves and increase production at these three fields, it would negatively affect the return on our investment in these fields.

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases. Many of our competitors have substantially larger financial and other resources. Other factors that affect our ability to acquire producing properties include available funds, available information about prospective properties and our standards established for minimum projected return on investment.

Oil and natural gas drilling and producing operations involve various risks.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. The seismic data and other technologies used by us do not provide conclusive knowledge, prior to drilling a well, that oil or natural gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivering systems and disrupt operations;
- compliance with environmental and other governmental requirements; and
- cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

The nature of these risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, cannot be insured. We could incur significant costs, related to these risks, that could have a material adverse effect on our results of operations, financial condition and cash flows.

Our CO_2 tertiary recovery projects require a significant amount of electricity to operate the facilities. If these costs were to increase significantly, it could have an adverse effect upon the profitability of these operations.

We depend on our key personnel.

We believe our continued success depends on the collective abilities and efforts of our senior management. The loss of one or more key personnel could have a material adverse effect on our results of operations. We do not have any employment agreements and do not maintain any key man life insurance policies. Additionally, if we are unable to find, hire and retain needed key personnel in the future, our results of operations could be materially and adversely affected.

The loss of more than one of our large oil and natural gas purchasers could have a material adverse effect on our operations.

For the year ended December 31, 2005, three purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 61% of these revenues. We would not expect the loss of any single purchaser to have a material adverse effect upon our operations. However, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive.

Estimating our reserves, production and future net cash flow is difficult to do with any certainty.

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. There are numerous uncertainties about when a property may have proved reserves as compared to potential or probable reserves, particularly relating to our tertiary recovery operations. Actual results most likely will vary from our estimates. Also, the use of a 10% discount factor for reporting purposes, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject. Any significant inaccuracies in these interpretations or assumptions or changes of conditions could result in a reduction of the quantities and net present value of our reserves.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs and other factors. Downward revisions of our reserves could have an adverse affect on our financial condition, operating results and cash flows.

The reserve data included in documents incorporated by reference represent only estimates. In accordance with requirements of the SEC, the estimates of present values are based on prices and costs as of the date of the estimates. Actual future prices and costs may be materially higher or lower than the prices and cost as of the date of the estimate.

As of December 31, 2005, approximately 44% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

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

Exploration for and development, exploitation, production and sale of oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax laws and environmental laws and regulations. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws, regulations or incremental taxes and fees, could harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations.

Matters subject to regulation include oil and gas production and saltwater disposal operations and our processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials, discharge permits for drilling operations, spacing of wells, environmental protection and taxation. We could incur significant costs as a result of violations of or liabilities under environmental or other laws, including third-party claims for personal injuries and property damage, reclamation costs, remediation and clean-up costs resulting from oil spills and discharges of hazardous materials, fines and sanctions, and other environmental damages.

Our level of indebtedness may adversely affect operations and limit our growth.

As of January 31, 2006, we have approximately $100.0 million available on our borrowing base under our bank credit facility. The next semi-annual redetermination of the borrowing base for our bank credit facility will be on April 1, 2006. Our bank borrowing base is adjusted at the banks' discretion and is based in part upon external factors over which we have no control. If our then redetermined borrowing base is less than our outstanding borrowings under the facility, we will be required to repay the deficit over a period of six months.

We may incur additional indebtedness in the future under our bank credit facility in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. Further, our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. If oil and natural gas prices were to decline significantly, particularly for an extended period of time, our degree of leverage could increase substantially. The level of our indebtedness could have important consequences, including but not limited to, the following:

- a substantial portion of our cash flows from operations may be dedicated to servicing our indebtedness and would not be available for other purposes;
- our business may not generate sufficient cash flow from operations to enable us to continue to meet our obligations under our indebtedness;
- our level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate and other purposes;
- our interest expense may increase in the event of increases in interest rates, because certain of our borrowings are at variable rates of interest;
- our vulnerability to general adverse economic and industry conditions may increase, potentially restricting us from making acquisitions, introducing new technologies or exploiting business opportunities;
- our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments may be limited by the covenants contained in the agreements governing our outstanding indebtedness limit; and
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry. Our failure to comply with such covenants could result in an event of default under such debt instruments which, if not cured or waived, could have a material adverse effect on us.

If we are unable to generate sufficient cash flow or otherwise obtain funds necessary to make required payments on our indebtedness or if we otherwise fail to comply with the various covenants in such indebtedness, including covenants in our bank credit facility, we would be in default. This default would permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness, including the subordinated notes, or result in our bankruptcy. Our ability to meet our obligations will depend upon our future performance, which will be subject to prevailing economic conditions and to financial, business and other factors, including factors beyond our control.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

See "Item 1. Business – Oil and Gas Operations." We also have various operating leases for rental of office space, office and field equipment, and vehicles. See "Off-Balance Sheet Agreements – Commitments and Obligations" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 10, "Commitments and Contingencies," to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses, including those noted below. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that we may have a range of legal exposure that would require accrual. The estimate of the potential impact from the following legal proceedings on our financial position, overall results of operations or cash flows could change in the future.

Along with two other companies, we have been named in a lawsuit styled *J. Paulin Duhe, Inc. vs. Texaco, Inc., et al*, Cause No. 101,227, filed in late 2003 in the 16th Judicial District Court, Division "E," Terrebonne Parish, Louisiana, seeking restoration to its original condition of property on which oil has been produced over the past 70 years. The contract and tort claims by the plaintiffs allege surface and groundwater damage of 26 acres that are part of our Iberia Field in Iberia Parish, Louisiana. Recently, plaintiff's experts have initially alleged that clean-up of alleged contamination of the property would cost $79.0 million, although settlement offers by plaintiffs have already been made for much smaller sums. The property was originally leased to Texaco, Inc. for mineral development in 1934 and Denbury acquired its interest in the property in August 2000 from Manti Operating Company. During 2005, the courts ruled that the plaintiffs' claims were premature insofar as they sought to enforce the end of lease restoration obligation and dismissed that claim. Other claims were not dismissed and certain aspects of the litigation are ongoing. We believe that we are indemnified by the prior owner, which we expect to cover our exposure to most damages, if any, found to have occurred prior to the time that we purchased the property. We believe that the allegations of this lawsuit are subject to a number of defenses, are without merit and we and the other defendants plan to vigorously defend this lawsuit, and if necessary, we will seek indemnification from the prior owner.

On December 29, 2003, an action styled *Harry Bourg Corporation vs. Exxon Mobil Corporation, et al,* Cause No. 140749, was filed in the 32nd Judicial District Court, Terrebonne Parish, Louisiana against Denbury and 11 other oil companies and their predecessors alleging damage as the result of mineral exploration activities conducted by these oil and gas operators/ companies over the last 60 years. Plaintiff has asked for restoration of the 10,000-acre property and/or damages in claims made under tort law and various oil and gas contracts. The Bourg Corporation produced preliminary expert reports that allege damages of approximately $100.0 million against the defendants as a group. Discovery is continuing in this case, with trial currently set for June 2006. Depending on the outcome of the case, we may have indemnification obligations to prior owners. We believe we have historical documents and matters of fact that we believe provide strong defenses against these claims and we plan to vigorously defend this lawsuit along with the other defendants.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

A special meeting of the stockholders was held on October 19, 2005, for the purposes of: (1) approving an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 100,000,000 shares to 250,000,000 shares; (ii) approving an amendment to our Restated Certificate of Incorporation to split our common shares 2-for-1; and (iii) granting authority to the Company to extend the solicitation period in the event that the special meeting is postponed or adjourned for any reason. At the record date, September 6, 2005, 57,153,230 shares of common stock were outstanding and entitled to one vote per share upon all matters submitted at the meeting. Holders of 51,315,563 shares of common stock, representing approximately 90% of the total issued and outstanding shares of common stock, were present in person or by proxy at the meeting to cast their vote. All matters were approved as listed below.

With respect to the amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 100,000,000 shares to 250,000,000 shares, the votes were cast as follows:

FOR	AGAINST	ABSTENTIONS
50,448,960	859,097	7,506

With respect to approving an amendment to our Restated Certificate of Incorporation to split our common shares 2-for-1, the votes were cast as follows:

FOR	AGAINST	ABSTENTIONS
51,252,432	51,750	11,381

With respect to approving an amendment to grant authority to extend the solicitation period in the event that the special meeting is postponed or adjourned for any reason, the votes were cast as follows:

FOR	AGAINST	ABSTENTIONS
24,246,544	24,131,812	2,937,206

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock Trading Summary

The following table summarizes the high and low reported sales prices on days in which there were trades of Denbury's common stock on the New York Stock Exchange (NYSE), for each quarterly period for the last two fiscal years. The sales prices are adjusted to reflect the 2-for-1 stock split on October 31, 2005. As of February 28, 2006, the number of record holders of Denbury's common stock was 678. Management believes, after inquiry, that the number of beneficial owners of Denbury's common stock is in excess of 9,700. On February 28, 2006, the last reported sales price of Denbury's Common Stock, as reported on the NYSE, was $28.35 per share.

	2005		2004	
	HIGH	LOW	HIGH	LOW
First Quarter	**$18.32**	**$12.37**	$ 8.47	$ 6.63
Second Quarter	**20.53**	**14.02**	10.87	8.36
Third Quarter	**25.71**	**19.95**	13.10	9.30
Fourth Quarter	**25.50**	**19.36**	14.65	12.03

We have never paid any dividends on our common stock and we currently do not anticipate paying any dividends in the foreseeable future. Also, we are restricted from declaring or paying any cash dividends on our common stock under our bank loan agreement. No unregistered securities were sold by the Company during 2005.

Equity Compensation Plan Information

The following table summarizes information about Denbury's equity compensation plans as of December 31, 2005.

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS (A)	WEIGHTED AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS (B)	NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE UNDER EQUITY COMPENSATION PLANS (EXCLUDING SECURITIES REFLECTED IN COLUMN A) (C)
EQUITY COMPENSATION PLANS APPROVED BY SECURITY HOLDERS:			
Stock Option Plan	**8,370,610**	**$ 6.64**	**—**
2004 Omnibus Plan	**1,035,462**	**19.66**	**1,644,538**
Employee Stock Purchase Plan	**—**	**—**	**452,371**
EQUITY COMPENSATION PLANS NOT APPROVED BY SECURITY HOLDERS:			
Director Compensation Plan	**—**	**—**	**138,229**
	9,406,072	**$ 8.07**	**2,235,138**

Our Directors Compensation Plan adopted effective July 1, 2000, as amended on February 22, 2001, and May 11, 2005, allows each non-employee director to make an annual election to receive his or her compensation in either cash or in shares of our common stock. The number of shares issued to a director who elects to receive shares of common stock under the Director Plan is calculated by dividing the director fees to be paid to such director by the average price of the Company's common stock for the 10 trading days prior to the date the fees are payable. Generally, director's fees are paid quarterly. We initially reserved 200,000 shares for issuance under the Director Plan, for directors who elect to receive their compensation in stock.

ITEM 6. SELECTED FINANCIAL DATA

	YEAR ENDED DECEMBER 31,				
(IN THOUSANDS, UNLESS OTHERWISE NOTED)	2005	2004[(1)]	2003	2002	2001[(1)]
CONSOLIDATED STATEMENTS OF OPERATIONS DATA:					
Revenues	**$ 560,392**	$382,972	$ 333,014	$ 285,152	$ 285,111
Net income	**166,471**	82,448	56,553[(2)]	46,795	56,550
Net income per common share[(3)]:					
Basic	**1.49**	0.75	0.52[(2)]	0.44	0.57
Diluted	**1.39**	0.72	0.51[(2)]	0.43	0.56
Weighted average number of common shares outstanding[(3)]:					
Basic	**111,743**	109,741	107,763	106,487	98,650
Diluted	**119,634**	114,603	110,928	108,730	100,722
CONSOLIDATED STATEMENTS OF CASH FLOW DATA:					
Cash provided by (used by):					
Operating activities	**$ 360,960**	$168,652	$ 197,615	$ 159,600	$ 185,047
Investing activities	**(383,687)**	(93,550)	(135,878)	(171,161)	(318,830)
Financing activities	**154,777**	(66,251)	(61,489)	12,005	134,986
PRODUCTION (DAILY):					
Oil (Bbls)	**20,013**	19,247	18,894	18,833	16,978
Natural gas (Mcf)	**58,696**	82,224	94,858	100,443	85,238
BOE (6:1)	**29,795**	32,951	34,704	35,573	31,185
UNIT SALES PRICE (EXCLUDING HEDGES):					
Oil (per Bbl)	**$ 50.30**	$ 36.46	$ 27.47	$ 22.36	$ 21.34
Natural gas (per Mcf)	**8.48**	6.24	5.66	3.31	4.12
UNIT SALES PRICE (INCLUDING HEDGES):					
Oil (per Bbl)	**$ 50.30**	$ 27.36	$ 24.52	$ 22.27	$ 21.65
Natural gas (per Mcf)	**7.70**	5.57	4.45	3.35	4.66
COSTS PER BOE:					
Lease operating expenses	**$ 9.98**	$ 7.22	$ 7.06	$ 5.48	$ 4.84
Production taxes and marketing expenses	**2.54**	1.55	1.17	0.92	0.96
General and administrative	**2.62**	1.78	1.20	0.96	0.89
Depletion, depreciation, and amortization	**9.09**	8.09	7.48	7.26	6.27
PROVED RESERVES:					
Oil (MBbls)	**106,173**	101,287	91,266	97,203	76,490
Natural gas (MMcf)	**278,367**	168,484	221,887	200,947	198,277
MBOE (6:1)	**152,568**	129,369	128,247	130,694	109,536
CONSOLIDATED BALANCE SHEET DATA:					
Total assets	**$1,505,069**	$992,706	$ 982,621	$ 895,292	$ 789,988
Total long-term liabilities	**617,343**	368,128	434,845	432,616	360,882
Stockholders' equity[(4)]	**733,662**	541,672	421,202	366,797	349,168

(1) We sold Denbury Offshore, Inc. in July 2004. We acquired Matrix Oil and Gas Inc. in July 2001.

(2) In 2003, we recognized a gain of $2.6 million for the cumulative effect adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The adoption of SFAS No. 143 increased basic and diluted net income per common share by $0.02. In April 2003, we recorded a pre-tax charge of $17.6 million associated with the early debt retirement.

(3) On October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years shares and earnings per share has been retroactively restated to reflect the stock split.

(4) We have never paid any dividends on our common stock.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi, own the largest reserves of carbon dioxide ("CO_2") used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage onshore Louisiana, Alabama, and in the Barnett Shale play near Fort Worth, Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, including secondary and tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have three primary field offices located in Houma, Louisiana; Laurel, Mississippi; and Cleburne, Texas.

2005 Overview

Continued expansion of our tertiary operations. Since we acquired our first carbon dioxide tertiary flood in Mississippi over six years ago, we have gradually increased our emphasis on these types of operations. We particularly like this play because of its risk profile, rate of return and lack of competition in our operating area. Generally, from East Texas to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of CO_2 that we own drive the play. Please refer to the section entitled "CO_2 Operations" below for a discussion of these operations, their potential, and the ramifications of our continuing emphasis on these operations.

Having enough CO_2 is one of the most important ingredients, if not the key ingredient, to our tertiary operations. During 2005 we increased our proved CO_2 reserve quantities by 74%, from 2.7 Tcf as of December 31, 2004, to approximately 4.6 Tcf as of December 31, 2005 (both of these quantities are on a working interest basis – see "CO_2 Operations – CO_2 Resources" for further information).

Operating Results. Earnings and cash flow were at record annual levels in 2005, primarily as a result of high commodity prices. Production increased approximately 6% over the prior year's production after adjusting for the production associated with our offshore properties sold in July 2004, even though we deferred approximately 1,100 BOE/d during 2005 as a result of two hurricanes (See "Operating Income – Production" below). Virtually all expenses increased during 2005, on both an absolute and per BOE basis, as we experienced cost increases in almost every aspect of our business, as much as 20% to 30% per annum for certain items. Operating expenses also increased as a result of our increased emphasis on tertiary operations, which have higher operating costs per BOE than our other properties. Nevertheless, during 2005 the high commodity prices more than offset the higher expenses. As has been our practice for several years, we are reinvesting virtually all of our cash flow in new projects, with a desire to (i) further increase our production and reserves, and (ii) keep our balance sheet strong by limiting our exploration and development budget to an amount approximately equal to our cash flow from operations. During 2005, our proved reserves increased from 129.4 MMBOE as of December 31, 2004, to 152.6 MMBOE as of December 31, 2005, replacing approximately 313% of our 2005 production, over 85% of which was from internal organic growth and the balance from acquisitions.

Net income for 2005 was $166.5 million, approximately double 2004 net income of $82.4 million and nearly a three-fold increase over 2003 net income of $56.6 million. Lower expense on our commodity hedges improved our net income. We paid out approximately $16.8 million during 2005 as compared to $84.6 million during 2004 and $62.2 million during 2003 in settlement payments on our commodity hedges (see "Market Risk Management"). As our financial position has improved over the last few years, we have generally hedged less, thus reducing our out of pocket cash payments, even though commodity prices have continued to increase.

Stock Split. On October 19, 2005, our stockholders approved an amendment to our certificate of incorporation to increase our authorized shares of common stock from 100 million shares to 250 million shares and to split our common stock on a two-for-one basis. Stockholders of record as of the close of business on October 31, 2005, received one additional share of Denbury common stock for each share of common stock held at that time. All per share numbers for all periods included herein have been restated for this two-for-one split.

2004 Sale of Offshore Operations. On July 20, 2004, we closed the sale of Denbury Offshore, Inc., a subsidiary that held our offshore assets, for approximately $187 million (after sale adjustments). Our offshore properties made up approximately 12% of our year-end 2003 proved reserves (approximately 96 Bcfe as of December 31, 2003) and represented approximately 25% (9,114 BOE/d) of our 2004 second quarter production.

Recent Acquisitions

On January 31, 2006, we completed an acquisition of three producing oil properties that are future potential CO_2 tertiary oil flood candidates: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. We expect to begin our initial tertiary development work at Tinsley Field during 2006 with more extensive development planned for 2007. The timing of tertiary development at Citronelle Field is uncertain as we will need to build a 60- to 70-mile pipeline extension of our CO_2 line to East Mississippi before flooding can commence, and South Cypress Creek will probably be flooded following our initial development of our other East Mississippi properties. See "CO_2 Operations" for further information regarding our CO_2 operations.

The preliminary adjusted purchase price for these three properties was approximately $248 million, after adjusting for interim net cash flow and minor purchase price adjustments. The acquisition was funded with proceeds of the $150 million of senior subordinated notes issued in December 2005 and bank financing under the Company's existing credit facility, bringing the outstanding balance of the Company's bank debt as of January 31, 2006, to approximately $100 million.

These three fields are currently producing approximately 2,200 BOE/d net to the acquired interests, and have proved reserves of approximately 14.4 million BOEs. We operate all three fields and own the majority of the working interest.

During 2005, we reached an agreement with Southern Natural Gas Company to acquire a 102-mile natural gas pipeline that runs from Gwinville Field in Central Mississippi to near Lake St. John Field, near the Louisiana/Mississippi border. This pipeline crosses our existing 20-inch CO_2 pipeline in Southwest Mississippi and will allow us to transport CO_2 to two oil fields we acquired during 2005, Lake St. John and Cranfield Fields. The purchase price and associated anticipated remediation work is estimated at approximately $5.2 million. Closing of the acquisition is subject to regulatory approval, which may take up to six months. Prior to converting the pipeline to CO_2 service, a smaller 17-mile natural gas pipeline will need to be constructed to replace natural gas service to the local communities currently being serviced by the pipeline.

Capital Resources and Liquidity

Our current capital budget for 2006, excluding any potential acquisitions, is approximately $494 million, which at commodity futures prices as of mid-February appears to be slightly more than our anticipated cash flow from operations. As has been our practice in the past, we attempt to reinvest all of our available cash flow from operations to find additional reserves and increase production. We monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, during the last few years as commodity prices have increased, we have increased our capital budget throughout the year. As a result of the recent cost inflation in our industry, many of our recent budget increases have related to escalating costs rather than additional projects. In this inflationary environment, we often have to either increase our capital budget or consider the elimination of a portion of our planned projects. We anticipate that we would fund any minor differences between our capital budget and cash flow from operations with bank debt, but if the difference becomes significant, we would likely postpone some of our projects. As of February 28, 2006, we had approximately $100 million of unused borrowing base on our bank credit line, which in our opinion could be significantly expanded if desired.

We plan to spend approximately 50% of our capital budget on tertiary related projects and approximately 25% in the Barnett Shale area, with the balance split almost equally between our other operating areas. Although we now control most of the fields along our existing CO_2 pipeline in Southwest Mississippi, there are several fields in East Mississippi that could be acquired to further expand our planned tertiary operations there, plus we are continuing to seek additional interests in the fields that we currently own. Further, we would like to add additional phases or areas of tertiary operations by acquiring other old oil fields in other parts of our region of operations, building a CO_2 pipeline to those areas and initiating additional tertiary floods. The purchase price of these potential tertiary fields can vary widely, depending on the level of existing production and conventional oil reserves, making it impractical to forecast our acquisition expenditures. We would likely fund any acquisitions with debt, supplemented as we feel necessary with equity. Although we are comfortable with our existing debt levels, they are higher than they have been the last couple of years because we funded the recently closed $248 million property acquisition (see "Recent Acquisitions") with debt. Since it is our desire to maintain a strong financial position, it is unlikely that we will increase our debt levels by any significant amount in the near future other than on a temporary basis, and we have not eliminated the possibility of issuing equity to reduce part, or all, of the bank debt incurred for the recent acquisition. We could also generate cash, if desired, by refinancing our essentially completed $50 million CO_2 pipeline to East Mississippi, recouping our expended capital and instead paying for the cost of the pipeline over time. With our current credit availability and other options that we believe are available to us, we do not anticipate having any liquidity issues in the foreseeable future.

At December 31, 2005, we had outstanding $225 million (principal amount) of 7.5% subordinated notes due 2013, $150 million (principal amount) of 7.5% subordinated notes due 2015, approximately $9.4 million of capital lease commitments, no bank debt, and working capital of $145.1 million. We borrowed $100 million on our bank line at the end of January and used available cash to fund the $248 million acquisition, which closed on January 31, 2006.

Sources and Uses of Capital Resources

During 2005, we spent $292.8 million on oil and natural gas exploration and development expenditures, $76.8 million on CO_2 exploration and development expenditures (including approximately $46.0 million for our CO_2 pipeline to East Mississippi), and approximately $70.9 million on property acquisitions, for total capital expenditures of approximately $440.5 million. Our exploration and development expenditures included approximately $147.8 million spent on drilling, $25.5 million of geological, geophysical and acreage expenditures and $135.1 million spent on facilities and recompletion costs. Our 2005 acquisition expenditures include the purchase of additional interest and acreage in the Barnett Shale area and purchase of two oil fields, Cranfield and Lake St. John Fields, which may be potential tertiary flood candidates in the future. Our $440.5 million of capital expenditures included an increase of $18.2 million in our accrued capital expenditures, with the remaining cash portion of our capital expenditures funded primarily with $361.0 million of cash flow from operations and approximately $57 million of short-term investments remaining at December 31, 2004, from the sale of our offshore properties during 2004. Additionally, we issued $150 million of subordinated debt in December 2005 and raised $14.4 million during 2005 from the sale of another volumetric production payment of CO_2 to Genesis Energy, L.P. ("Genesis"), along with a related long-term CO_2 supply agreement with an industrial customer. All of these sources not only funded our capital expenditures, but also increased our cash balance at year-end to $165.1 million, with a portion of such funds used in January 2006 to partially fund the $248 million acquisition. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under "Results of Operations – Operating Results" below) was $343.4 million for 2005, while cash flow from operations for the same period, the GAAP measure, was $361.0 million.

During 2004, we spent $167.0 million on oil and natural gas exploration and development expenditures, $42.4 million on CO_2 exploration and development expenditures, and approximately $18.9 million on property acquisitions, for total capital expenditures of approximately $228.3 million. Our exploration and development expenditures included approximately $138.9 million spent on drilling, $18.9 million of geological, geophysical and acreage expenditures and $51.6 million spent on facilities and recompletion costs. We funded these expenditures with $168.7 million of cash flow from operations, with the balance funded with net proceeds from the sale of our offshore properties. We paid back all of our bank debt during the third quarter of 2004 with the offshore sale proceeds, leaving us with approximately $33.0 million of cash and $57.2 million of short-term investments as of December 31, 2004. We also raised $4.8 million during the third quarter of 2004 from the sale of another volumetric production payment of CO_2 to Genesis, along with a related long-term CO_2 supply agreement with an industrial customer. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under "Results of Operations – Operating Results") was $200.2 million for 2004, while cash flow from operations, the GAAP measure, was $168.7 million.

During 2003, we generated approximately $197.6 million of cash flow from operations and generated an additional $29.4 million of cash from sales of oil and gas properties. The largest single asset sale was the sale of Laurel Field, acquired from COHO in August 2002, which netted us approximately $25.9 million. Later in the year, we also sold a volumetric production payment to Genesis, which netted us approximately $23.9 million of cash. During 2003, we spent $146.6 million on oil and natural gas exploration and development expenditures, $22.7 million on CO_2 capital investments and acquisitions, and approximately $11.8 million on oil and natural gas property acquisitions, for total capital expenditures of approximately $181.1 million. Our exploration and development expenditures included approximately $115.3 million spent on drilling, $15.7 million of geological, geophysical and acreage expenditures and $35.2 million spent on facilities and recompletion costs. In addition, during 2003 we incurred approximately $15.6 million of costs to refinance our previously outstanding subordinated debt. The $147.3 million of net total expenditures (including the $15.6 million of debt refinancing costs but net of property sales proceeds) was funded by our cash flow from operations, with the balance used to reduce our total debt by approximately $50.0 million.

Off-Balance Sheet Arrangements

Commitments and Obligations

We have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees, other than as disclosed in this section. We have no debt or equity triggers based upon our stock or commodity prices. Our dollar denominated obligations that are not on our balance sheet include our operating leases, which at year-end 2005 totaled $37.2 million relating primarily to the lease financing of certain equipment for CO_2 recycling facilities at our tertiary oil fields. We also have several leases relating to office space and other minor equipment leases. Additionally, we have dollar related obligations that are not currently recorded on our balance sheet relating to various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs forecasted in our proved reserve reports. For a further discussion of our future development costs and proved reserves, see "Results of Operations – Depletion, Depreciation and Amortization" below.

At December 31, 2005, we had a total of $460,000 outstanding in letters of credit. Genesis Energy, Inc., our 100% owned subsidiary that is the general partner of Genesis, has guaranteed the bank debt of Genesis, which consists of $10.1 million in letters of credit at December 31, 2005. There were no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. at December 31, 2005. We do not have any material transactions with related parties other than sales of production, transportation arrangements, and capital leases with Genesis made in the ordinary course of business, and volumetric production payments of CO_2 ("VPP") sold to Genesis as discussed in Note 3 to our Consolidated Financial Statements.

Management's Discussion and Analysis of Financial Condition and Results of Operations

A summary of our obligations is presented in the following table:

	PAYMENTS DUE BY PERIOD						
AMOUNTS IN THOUSANDS	TOTAL	2006	2007	2008	2009	2010	THEREAFTER
CONTRACTUAL OBLIGATIONS:							
Subordinated debt[a]	$ 375,000	$ —	$ —	$ —	$ —	$ —	$375,000
Estimated interest payments on subordinated debt[a]	234,262	28,125	28,125	28,125	28,125	28,125	93,637
Operating lease obligations	37,236	6,971	6,959	6,812	5,931	4,392	6,171
Capital lease obligations[b]	9,411	1,185	1,185	1,185	1,185	1,185	3,486
Capital expenditure obligations[c]	90,682	43,763	26,249	15,990	4,680	—	—
Other long-term liabilities reflected in our Consolidated Balance Sheet:							
Derivative liabilities[d]	10,458	2,774	3,706	3,978	—	—	—
OTHER CASH COMMITMENTS:							
Future development costs on proved oil and gas reserves, net of capital obligations[e]	441,123	203,289	133,229	59,746	16,294	17,119	11,446
Future development cost on proved CO_2 reserves, net of capital obligations[f]	134,759	24,759	17,000	17,000	—	—	76,000
Asset retirement obligations[g]	69,066	1,820	1,057	3,723	455	2,399	59,612
Total	$1,401,997	$312,686	$217,510	$136,559	$56,670	$53,220	$625,352

(a) These long-term borrowings and related interest payments are further discussed in Note 6 to the Consolidated Financial Statements. This table assumes that our long-term debt is held until maturity.

(b) Represents future minimum cash commitments to Genesis under capital leases in place at December 31, 2005, primarily for transportation of crude oil and CO_2. Approximately $3 million of these payments represents interest.

(c) Represents future minimum cash commitments under contracts in place as of December 31, 2005, primarily for drilling rig services and well related costs. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that occur during the subsequent several months and are usually part of our normal operating expenses or part of our capital budget, which for 2006 is currently set at $494 million. In addition, we have recurring expenditures for such things as accounting, engineering and legal fees, software maintenance, subscriptions, and other overhead type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. We have not attempted to estimate these types of expenditures in this table as most could be quickly cancelled with regard to any specific vendor, even though the expense itself may be required for ongoing normal operations of the Company.

(d) Represents the estimated future payments under our derivative obligations based on the futures market prices as of December 31, 2005. These amounts will change as oil and natural gas commodity prices change. The estimated fair market value of our oil and natural gas commodity derivatives at December 31, 2005, was a $9.4 million liability. See further discussion of our derivative contracts and their market price sensitivities in "Market Risk Management" below in this Management's Discussion and Analysis of Financial Condition and in Note 9 to the Consolidated Financial Statements.

(e) Represents projected capital costs as scheduled in our December 31, 2005 proved reserve report that are necessary in order to recover our proved undeveloped oil and natural gas reserves. These are not contractual commitments and are net of any other capital obligations shown above.

(f) Represents projected capital costs as scheduled in our December 31, 2005 proved reserve report that are necessary in order to recover our proved undeveloped reserves for our CO_2 source wells used to produce CO_2 for our tertiary operations. These are not contractual commitments and are net of any other capital obligations shown above.

(g) Represents the estimated future asset retirement obligations on an undiscounted basis. The discounted asset retirement obligation of $27.1 million, as determined under SFAS No. 143, is further discussed in Note 4 to the Consolidated Financial Statements.

Long-term contracts require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis pursuant to three volumetric production payments ("VPP") entered into during 2003, 2004 and 2005. Based upon the maximum amounts deliverable as stated in the contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 390 Bcf of CO_2 to these customers over the next 18 years; however, since the group as a whole has historically taken less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that our commitment would likely be reduced to approximately 264 Bcf. The maximum volume required in any given year is approximately 113 MMcf/d, although based on our current level of deliveries, this would likely be reduced to approximately 74 MMcf/d. Given the size of our proven CO_2 reserves at December 31, 2005 (approximately 4.6 Tcf before deducting approximately 237.1 Bcf for the three VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we will be able to meet these delivery obligations.

Results of Operations

CO_2 Operations

Overview. Our interest in tertiary operations has increased to the point that approximately 50% of our 2005 expenditures and 2006 capital budget are dedicated to tertiary related operations. We particularly like this play as (i) it is lower risk and more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (generally in the twenties, depending on the specific field and area), and (iii) we have virtually no competition for this type of activity in our geographic area. Generally, from East Texas to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of CO_2 that we own drive the play.

We talk about our tertiary operations by labeling operating areas or groups of fields as phases. Phase I is in Southwest Mississippi and includes several fields along our 183-mile CO_2 pipeline that we acquired in 2001. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. Phase II, which we are just starting with the completion of our CO_2 pipeline to East Mississippi, includes Eucutta, Soso, Martinville and Heidelberg Fields. With the properties acquired in our recent acquisition that closed in January 2006 (see "Recent Acquisitions" above), we have labeled the planned operations at Tinsley Field, Northwest of Jackson Dome, as Phase III. Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border west of the fields in Phase I.

CO_2 Resources. In February 2001, we acquired the sources of CO_2 located near Jackson, Mississippi, and a 183-mile pipeline to transport it to our oil fields. Since February 2001, we have acquired two and drilled nine additional CO_2 producing wells, significantly increasing our estimated proved CO_2 reserves from approximately 800 Bcf at the time of acquisition to approximately 4.6 Tcf as of December 31, 2005, approximately 500 Bcf more than we estimate we need for our existing and currently planned phases of tertiary operations. The estimate of 4.6 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net revenue interest ownership is approximately 3.8 Tcf, and is included in the evaluation of proven CO_2 reserves prepared by DeGolyer & MacNaughton. In discussing the available CO_2 reserves, we make reference to the gross amount of proved reserves, as this is the amount that is available both for Denbury's tertiary recovery programs and industrial users, as Denbury is responsible for distributing the entire CO_2 production stream for both of these uses. We currently estimate that it will take approximately 937 Bcf of CO_2 to develop and produce the proved tertiary recovery reserves we have recorded at December 31, 2005.

Today, we own every known producing CO_2 well in the region, providing us a significant strategic advantage in the acquisition of other properties in Mississippi and Louisiana that could be further exploited through tertiary recovery. As of January 2006, we estimate that we are capable of producing approximately 450 MMcf/d of CO_2, over five times the rate that we were capable of producing at the time of our initial acquisition in 2001. We continue to drill additional CO_2 wells, with three more wells planned for 2006, in order to further increase our production capacity and potentially increase our proven CO_2 reserves. Our drilling activity at Jackson Dome will continue beyond 2006 as our current forecasts for the four planned phases suggest that we will need over 800 MMcf/d of CO_2 production by 2011.

In addition to using CO_2 for our tertiary operations, we sell CO_2 to third party industrial users under long-term contracts. Most of these industrial contracts have been sold to Genesis along with a volumetric production payment for the CO_2.

Our average daily CO_2 production during 2003, 2004 and 2005 was approximately 170 million, 218 million, and 242 million cubic feet per day, of which approximately 62% in 2003, and 73% in 2004, and 73% in 2005 was used in our tertiary recovery operations, with the balance delivered to Genesis under the volumetric production payments or sold to third party industrial users.

We spent approximately $0.16 per Mcf in operating expenses to produce our CO_2 during 2005, more than our 2004 annual average of $0.12 per Mcf, primarily due to increased labor, utilities and equipment rental expenses during 2005, coupled with higher royalty expenses because several of our royalties correlate with oil prices. During 2003, we spent approximately $0.15 per Mcf to produce our CO_2. Our estimated total cost per thousand cubic feet of CO_2 during 2005 was approximately $0.25, after inclusion of depreciation and amortization expense related to the CO_2 production, as compared to approximately $0.21 during 2004.

Overview of Tertiary Economics. Most of our tertiary operations are economic at oil prices in the twenties, although the economics vary by field. Our costs have escalated during the last few years due to general cost inflation in the industry and this trend is expected to continue. Our inception to date finding and development costs (including future development and abandonment costs) for our tertiary oil fields through December 31, 2005, was approximately $7.50 per BOE. Currently, we forecast that these costs will range from $3 to $11 per BOE over the life of each field, depending on the state of a particular field at the time we begin operations, the amount of potential oil, the proximity to a pipeline or other facilities, etc. Our operating costs for tertiary operations averaged $12.00 per BOE in 2005 and are expected to range from $10 to $15 per BOE over the life of each field, again depending on the field itself.

Oil quality is another significant factor that impacts the economics. In Phase I (Southwest Mississippi), the light sweet oil produced from our tertiary operations receives near NYMEX prices, while the average discount to NYMEX for the lower quality oil produced from the fields in Phase II (East Mississippi), some of which we plan to start flooding during 2006, was $9.39 per BOE during 2005, a differential that is significantly higher than historical averages and one that appears to increase as oil prices increase.

While these economic factors have wide ranges, our rate of return from these operations has generally been better than our traditional oil and gas operations, and thus our tertiary operations have become our single most important focus area. While it is extremely difficult to accurately forecast future production, we do believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk, and thus will be the backbone of our Company's growth for the foreseeable future. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future that could delay our overall tertiary development program. We believe that such delays, if any, should only be temporary.

Financial Statement Impact of CO_2 Operations. The increasing emphasis on CO_2 tertiary recovery projects has made, and will continue to make, an impact on our financial results and certain operating statistics.

First, there is a significant delay between the initial capital expenditures and the resulting production increases, as these tertiary operations require the building of facilities before CO_2 flooding can commence and it usually takes six to twelve months before the field responds (i.e., oil production commences) to the injection of CO_2. Further, as we expand to other areas, there will be times when we spend significant amounts of capital before we can recognize any proven reserves as these other areas, for the most part, will require an oil production response to the CO_2 injections before any oil reserves can be recorded. Further, even after a field has proven reserves, there will usually be significant amounts of additional capital required to fully develop the field.

Secondly, these tertiary projects are usually more expensive to operate than our other oil fields because of the cost of injecting and recycling the CO_2 (primarily due to the significant energy requirements to re-compress the CO_2 back into a liquid state for re-injection purposes). As commodity and energy prices increase, so do our operating expenses in these fields. Our operating cost for our tertiary operations during 2005 averaged $12.00 per BOE, as compared to an estimated cost of around $7 to $10 per BOE for a more traditional oil property. We allocate the cost to produce and transport the CO_2 between CO_2 used in our own oil fields and CO_2 sold to commercial users (including obligations covered by the volumetric production payments sold to Genesis). Most of our CO_2 operating expenses are allocated to our oil fields and are recorded as lease operating expenses on those fields. Since we expense all of the operating costs to produce and inject our CO_2, the operating costs per barrel will generally be higher at the inception of CO_2 injection before oil production is realized in a particular field. Our overall operating expenses on a per BOE basis will likely continue to increase as these operations constitute an increasingly larger percentage of our operations. Generally, these higher operating costs are somewhat offset by lower finding and development costs which helps to lower our overall depreciation and depletion rate (see also "Overview of Tertiary Economics" above).

Third, our net oil price relative to NYMEX prices may be affected by the oil produced from our tertiary operations (see "Overview of Tertiary Operations" above). Currently, all of our current CO_2 related oil production is from fields that produce light sweet oil and receive oil prices close to, and sometimes actually higher than, NYMEX prices. However, the oil produced from fields we plan to flood as part of Phase II have recently sold at a significant discount to NYMEX. The relative mix of this production, coupled with changing market conditions for the various types of crude, can cause our NYMEX differentials to fluctuate widely.

Analysis of CO_2 Tertiary Recovery Operating Activities. We currently have tertiary operations ongoing at Little Creek, Mallalieu, McComb, Smithdale and Brookhaven Fields, as well as various smaller adjacent fields. We project that our oil production from these operations will increase substantially over the next several years as we continue to expand this program by adding additional projects and phases. As of December 31, 2005, we had approximately 59.8 MMBbls of proven oil reserves related to tertiary operations (50.7 MMBbls of which was in Phase I and the balance in Phase II) and have identified and estimated significant additional oil potential in other fields that we own in this region. We plan to start CO_2 injections at three fields in Phase II within the first half of 2006, although we do not expect any material production response until 2007. During 2006, we will also start preliminary development work at Tinsley Field (Phase III) and at Cranfield (Phase IV).

Our oil production from our CO_2 tertiary recovery activities has steadily increased during the last few years, from 3,970 Bbls/d in 2002 to 9,215 Bbls/d during 2005. Our oil production in the third quarter of 2005 decreased 6% over second quarter 2005 levels primarily as a result of production deferred because of two hurricanes which disrupted our electrical power, forcing us to temporarily shut-in our production. Tertiary oil production represented approximately 48% of our total corporate oil production during the fourth quarter of 2005 and approximately 31% of our total corporate production during the same period on a BOE basis. We expect that this tertiary related oil production will continue to increase, although the increases are not always predictable or consistent. Following is a chart with our tertiary oil production by field for 2003, 2004 and by quarter for 2005.

	AVERAGE DAILY PRODUCTION (BOE/d)						
TERTIARY OIL FIELD	FIRST QUARTER 2005	SECOND QUARTER 2005	THIRD QUARTER 2005	FOURTH QUARTER 2005	2005	2004	2003
Brookhaven	**—**	**—**	**—**	**125**	**31**	—	—
Little Creek & Lazy Creek	**3,709**	**3,847**	**3,357**	**3,210**	**3,529**	3,148	3,093
Mallalieu (East and West)	**4,235**	**4,582**	**4,565**	**5,562**	**4,739**	3,351	1,578
McComb & Olive	**700**	**988**	**928**	**1,011**	**908**	285	—
Smithdale	**—**	**—**	**—**	**31**	**8**	—	—
Total tertiary oil production	**8,644**	**9,417**	**8,850**	**9,939**	**9,215**	6,784	4,671

Our operations in this area, as well as others, have had minor delays during 2005. These delays are caused by various factors: difficulties reentering certain injection wells, which has required that some wells be redrilled; delays in getting certain permits and right-of-ways; delays caused by the two hurricanes; and a general tightening of available materials and equipment in the industry. Generally, the fields are performing as anticipated, but 2005 tertiary oil production was not quite as high as originally expected because of these delays and the two hurricanes. In addition, the timing of specific well responses is not always possible to accurately forecast, so we could experience variances from our expected long-term oil production forecast.

In addition to higher energy costs to operate our tertiary recycling facilities related to higher commodity prices, we have experienced general cost inflation during the last few years. We have also leased a portion of our recycling and plant equipment used in our tertiary operations, which further increases operating expenses. Over the last three years we have leased certain equipment that qualify for operating lease treatment representing an underlying aggregate cost of approximately $30.3 million as of December 31, 2005, and we expect to enter into new leases for equipment during 2006 representing additional underlying costs of approximately $30 million. Further, the cost to produce our CO_2 increased during 2005 (see "CO_2 Resources" above), all of which resulted in an increase in our tertiary operating cost per BOE from $9.90 per BOE in 2004 to $12.00 per BOE during 2005. The absolute amount of operating expenses related to tertiary operations increased from $19.3 million during 2003 to $24.6 million during 2004 and $40.4 million during 2005.

Through December 31, 2005, we had spent a total of $273.5 million on fields currently being flooded (included allocated acquisition costs), and had received $303.5 million in net cash flow (revenue less operating expenses and capital expenditures), or net positive cash flow of $30.0 million. The proved oil reserves in our CO_2 fields have a PV-10 Value of $1.5 billion, using December 31, 2005, constant NYMEX pricing of $61.04 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties, but do include CO_2 source field lease operating costs and transportation costs. Through December 31, 2005, we had a balance of approximately $143.5 million of unrecovered costs for the CO_2 assets.

CO_2 Related Capital Budget for 2006. Tentatively, we plan to spend approximately $45 million in 2006 in the Jackson Dome area with the intent to add additional CO_2 reserves and deliverability for future operations. Approximately $105 million in capital expenditures is budgeted in 2006 for our Phase I properties (Southwest Mississippi) and approximately $55 million for Phase II properties (East Mississippi), plus an additional $29 million for properties in Phases III and IV, making our combined CO_2 related expenditures just under 50% of our 2006 capital budget.

Operating Income

Adjusted cash flow from operations (see discussion below regarding this non-GAAP measure) and net income have increased each year during the last three years, along with rising commodity prices. Production declined 5% from 2003 to 2004 and approximately 10% from 2004 to 2005, primarily related to the sale of our offshore properties in July 2004 and further impacted by the hurricanes during 2005, but the effect of the deferred production was more than offset by the higher commodity prices.

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS EXCEPT PER SHARE AMOUNTS	2005	2004	2003
Net income	**$166,471**	$ 82,448	$ 56,553
Net income per common share:			
Basic	**$1.49**	$0.75	$0.52
Diluted	**1.39**	0.72	0.51
Adjusted cash flow from operations	**$343,383**	$200,193	$189,802
Net change in assets and liabilities relating to operations	**17,577**	(31,541)	7,813
Cash flow from operations (GAAP measure)	**$360,960**	$168,652	$197,615

Adjusted cash flow from operations is a non-GAAP measure that represents cash flow provided by operations before changes in assets and liabilities, as calculated from our Consolidated Statements of Cash Flows. Cash flow from operations is the GAAP measure as presented in our Consolidated Statements of Cash Flows. In our discussion herein, we have elected to discuss these two components of cash flow provided by operations.

Adjusted cash flow from operations, the non-GAAP measure, measures the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe that it is important to consider adjusted cash flow from operations separately, as we believe it can often be a better way to discuss changes in operating trends in our business caused by changes in production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during that year. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices or significant changes in drilling activity.

The net change in assets and liabilities relating to operations is also important as it does require or provide additional cash for use in our business; however, we prefer to discuss its effect separately. For instance, as noted above, during 2003, our accounts payable and accrued liabilities increased as a result of our higher drilling activity level late in the year, particularly offshore, increasing our available cash from operations. During 2004, we had a $31.5 million difference between our adjusted cash flow from operations and our GAAP cash flow from operations. The most significant factor was the transfer of approximately $12.5 million of accrued production receivables relating to our offshore properties that existed as of the closing date to the offshore property purchaser. This reduction in accrued production receivables during 2004 was not considered a collection of receivables for our GAAP cash flow from operations. In addition to the effect of transferred receivables, our other accrued production receivables increased during the year due to the increase in commodity prices, and we reduced our accounts payable and accrued liabilities by approximately $10.5 million as a result of less overall activity as of year-end, both of which contributed to the significant difference between our 2004 adjusted cash flow and GAAP cash flow from operations. During 2005, we had a $17.6 million increase to our GAAP cash flow from operations resulting from the net change in assets and liabilities relating to operations. This is primarily due to higher accounts payable and accrued liabilities associated with increased capital spending levels as compared to the prior year. Our accrual for production receivables was higher at the end of 2005 than a year earlier, due to higher oil and natural gas prices, partially offsetting the benefit of higher accounts payable and accrued liabilities.

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Certain of our operating statistics for each of the last three years are set forth in the following chart:

IN THOUSANDS, EXCEPT UNIT PRICES AND PER BOE AMOUNTS	YEAR ENDED DECEMBER 31, 2005	2004	2003
AVERAGE DAILY PRODUCTION VOLUMES			
Bbls	**20,013**	19,247	18,894
Mcf	**58,696**	82,224	94,858
BOE(1)	**29,795**	32,951	34,704
OPERATING REVENUES			
Oil sales	**$367,414**	$256,843	$189,442
Natural gas sales	**181,641**	187,934	196,021
Total oil and natural gas sales	**$549,055**	$444,777	$385,463
OIL AND GAS DERIVATIVE CONTRACTS(2)			
Cash expense on settlements of derivative contracts	**$ (16,761)**	$ (84,557)	$ (62,210)
Non-cash derivative (expense) income	**(12,201)**	(1,270)	3,578
Total expense from oil and gas derivative contracts	**$ (28,962)**	$ (85,827)	$ (58,632)
OPERATING EXPENSES			
Lease operating expenses	**$108,550**	$ 87,107	$ 89,439
Production taxes and marketing expenses(3)	**27,582**	18,737	14,819
Total production expenses	**$136,132**	$105,844	$104,258
CO_2 sales and transportation fees(4)	**$ 8,119**	$ 6,276	$ 8,188
CO_2 operating expenses	**2,251**	1,338	1,710
CO_2 operating margin	**$ 5,868**	$ 4,938	$ 6,478
UNIT PRICES – INCLUDING IMPACT OF DERIVATIVE SETTLEMENTS(2)			
Oil price per Bbl	**$ 50.30**	$ 27.36	$ 24.52
Gas price per Mcf	**7.70**	5.57	4.45
UNIT PRICES – EXCLUDING IMPACT OF DERIVATIVE SETTLEMENTS(2)			
Oil price per Bbl	**$ 50.30**	$ 36.46	$ 27.47
Gas price per Mcf	**8.48**	6.24	5.66
OIL AND GAS OPERATING REVENUES AND EXPENSES PER BOE(1)			
Oil and natural gas revenues	**$ 50.49**	$ 36.88	$ 30.43
Lease operating expenses	**$ 9.98**	$ 7.22	$ 7.06
Production taxes and marketing expenses	**2.54**	1.55	1.17
Total oil and natural gas production expenses	**$ 12.52**	$ 8.77	$ 8.23

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas (BOE).

(2) See also Market Risk Management below for information concerning the Company's derivative transactions. Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts; see Note 9 to the Consolidated Financial Statements and "Critical Accounting Policies and Estimates – Oil and Gas Derivative Contracts" below.

(3) For 2005 and 2004, includes transportation expenses paid to Genesis of $4.0 million and $1.2 million, respectively.

(4) For 2005, 2004, and 2003 includes deferred revenue of $3.1 million, $2.4 million and $0.3 million respectively, associated with volumetric production payments and transportation income of $3.5 million, $2.7 million and $0.4 million, respectively, both from Genesis.

Production. Average daily production by area for 2003, 2004 and 2005, and each of the quarters of 2005 is listed in the following table (BOE/d).

	AVERAGE DAILY PRODUCTION (BOE/d)						
OPERATING AREA	FIRST QUARTER 2005	SECOND QUARTER 2005	THIRD QUARTER 2005	FOURTH QUARTER 2005	2005	2004	2003
Mississippi – non-CO_2 floods	**13,057**	**12,788**	**10,998**	**11,475**	**12,072**	13,085	13,638
Mississippi – CO_2 floods	**8,644**	**9,417**	**8,850**	**9,939**	**9,215**	6,784	4,671
Onshore Louisiana	**6,710**	**5,791**	**5,169**	**6,992**	**6,164**	7,630	8,222
Barnett Shale	**1,313**	**2,052**	**2,150**	**3,048**	**2,145**	587	224
Other[1]	**—**	**421**	**178**	**195**	**199**	—	—
Total production excluding offshore	**29,724**	**30,469**	**27,345**	**31,649**	**29,795**	28,086	26,755
Offshore Gulf of Mexico – Sold July 2004	**—**	**—**	**—**	**—**	**—**	4,865	7,949
Total Company	**29,724**	**30,469**	**27,345**	**31,649**	**29,795**	32,951	34,704

(1) Primarily represents production from an offshore property retained from the sale in July 2004.

As a result of the sale of our offshore properties in July 2004, total production decreased as listed in the above table. Adjusting for the offshore sale, overall production increased approximately 5% on a BOE/d basis during 2004 and approximately 6% during 2005, anchored by the increased production from our tertiary operations and Barnett Shale play, generally offset by overall declines in our onshore conventional properties in Mississippi and natural gas wells in Louisiana. However, other factors that caused fluctuations between the various periods should also be noted as outlined below.

During August and September, 2005, hurricanes Katrina and Rita came ashore, negatively affecting almost all of our existing production. While we did not incur any significant property damage as a result of either storm, we estimate that we deferred approximately 350,000 barrels of oil equivalent ("BOE") of production during the third quarter of 2005 as most of our fields were shut-in for periods ranging from several days to a few weeks, primarily because of a lack of power or because of flooding. As a result, production was lower in the third quarter than in the immediately prior quarter in every area of our operations except for the Barnett Shale play in Texas. While almost all of our wells had been returned to production by late October, we estimate that we deferred an additional 500 BOE/d of production in the fourth quarter as a result of the two hurricanes. In the aggregate, the deferred production from the two hurricanes lowered our 2005 average annual production rate by almost 1,100 BOE/d.

Most of the non-CO_2 fields in Mississippi have been on a slight decline during the last few years as a result of normal depletion. Heidelberg Field, our single largest field, which is located in this area, has partially offset this decline, as its production increased from 2003 to 2004, then declined slightly in 2005. Heidelberg production averaged 7,535 BOE/d during 2003, 7,775 BOE/d during 2004, and 7,312 BOE/d during 2005. Most production increases at Heidelberg are attributable to additional natural gas drilling in the Selma Chalk formation as Heidelberg's oil production has been slowly decreasing. Natural gas production at this field averaged 10.3 MMcf/d in 2003, 13.8 MMcf/d in 2004, and 14.1 MMcf/d in 2005, making Heidelberg Field our single largest natural gas producing field during 2005.

As more fully discussed in "CO_2 Operations" above, oil production from our tertiary operations has increased each year.

While our onshore Louisiana annual production average is less in 2005 than in 2004, as a result of drilling 19 successful wells during 2005 (including wells completed in January 2006), production increased in Louisiana during the fourth quarter of 2005 as compared to the prior quarters. As a result, we expect our 2006 average production in Louisiana to be higher than in 2005. Production in this area, predominately natural gas, is relatively short-lived in nature and can decline rapidly unless offset by new wells. As an example, Thornwell Field, an onshore Louisiana field, has been particularly volatile, averaging 2,487 BOE/d during 2003, 1,487 BOE/d during 2004, reaching a three-year low of 649 BOE/d during the second quarter of

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2005, but then increasing to 2,169 BOE/d during the fourth quarter of 2005 as a result of our drilling two successful wells during 2005. In spite of its short life and volatile production, we have generated a good return on investment at Thornwell, generating $43.5 million of net positive cash flow (operating revenues less operating expenses and capital expenditures) through December 31, 2005, with a remaining PV-10 Value of $132.5 million as of December 31, 2005 (based on SEC proved reserve report at year-end 2005 prices).

Natural gas production in the Barnett Shale has increased as a result of increased drilling activity in 2004 and 2005 and the acquisition of additional interests during the second quarter of 2005 that added approximately 1.5 MMcf/d of production. These wells are characterized by steep decline rates in their first year of production (as much as 50% to 60%), followed by a gradual leveling-off of production and a resultant slow decline rate, giving them an overall long production life. Natural gas production in this area is expected to further increase throughout 2006 as we anticipate drilling 45 to 50 wells in this area during 2006. We currently have four rigs running in this area.

Our production for 2005 was weighted toward oil (67%) and we expect a similar weighting toward oil in 2006 due to our increasing emphasis on tertiary operations, unless we make an acquisition that is predominantly natural gas.

Oil and Natural Gas Revenues. Our oil and natural gas revenues have increased for each of the last two years, primarily as a result of higher commodity prices, offset in part by lower production as a result of the sale of offshore properties. Between 2004 and 2005, revenues increased by 23%. The overall increase in commodity prices contributed $148.0 million in additional revenues, a 33% increase, partially offset by an overall decrease of $43.7 million (a 10% decrease) related to the 10% lower production volumes. Between 2003 and 2004, revenues increased by 15%. The overall increase in commodity prices contributed $77.8 million in additional revenues, a 20% increase; partially offset by an overall decrease in revenues of $18.5 million (a 5% decrease) related to the 5% lower production volumes.

During 2005, we made payments on our derivative contracts of $16.8 million, down from $84.6 million paid out during the prior year. Our 2005 payments related to a natural gas collar, lowering our effective net natural gas price by $0.78 per Mcf. During 2004, we paid out $64.1 million on our oil hedges ($9.10 per Bbl) and $20.4 million ($0.68 per Mcf) on our natural gas hedges relating to swaps and collars we purchased one to two years earlier when commodity prices were lower. About $30.5 million of the hedge payments related to swaps originally put in place to protect the rate of return for the COHO acquisition in August 2002. The payments in 2003 were similar in nature, but slightly less due to lower overall commodity prices. During 2003, we paid out $20.3 million on our oil hedges ($2.95 per Bbl) and $41.9 million ($1.21 per Mcf) on our natural gas hedges on generally the same type of swaps and collars. For 2006, we have hedged a lower percentage of our overall production, so we do not anticipate that our payments on our derivative contracts will reach the levels seen during 2003 and 2004. See "Market Risk Management" for a further discussion of our derivative activities.

Our net oil and natural gas prices have increased each year as outlined in the above table. These prices would have been even higher if our net price would have increased as much as NYMEX prices. During 2004 and continuing into 2005, the discount for our heavier, sour crude (which predominantly applies to our Eastern Mississippi production) increased significantly, lowering our overall net price relative to NYMEX. Our net oil price averaged $3.60 below NYMEX during 2003, increased to $4.91 during 2004, and further increased to $6.33 during 2005. This occurred in spite of our increasing light sweet oil production from our Phase I tertiary operations, which should have improved our overall net price as such crude receives near NYMEX prices and is becoming a higher percentage of our overall production. However, as evident in 2004 and 2005, the oil market is subject to significant and sudden changes and it is difficult to forecast these trends, although our experience indicates that the discount or NYMEX differential for our heavier sour crude increases as NYMEX oil prices increase.

During 2003 and 2004, there was less fluctuation in our natural gas prices relative to NYMEX. During both of those years, our net natural gas prices were at, or slightly above, the quoted NYMEX prices, primarily because of the high Btu content of our natural gas and the close proximity of our Louisiana natural gas production to Henry Hub. For 2003, we had an average $0.18 premium to NYMEX and for 2004, had a $0.02 premium to NYMEX. During 2005, our natural gas price averaged $0.49 below NYMEX, primarily due to the increasing natural production in the Barnett Shale area, which averaged $1.82 per Mcf below NYMEX. The NYMEX differential in this area appears to increase with higher natural gas prices; plus, the production in this area is growing and is expected to increase again during 2006. Although these factors could change depending on the overall natural gas market, we would expect these factors to gradually reduce our overall net natural gas price relative to NYMEX in the near future.

Operating Expenses. Our lease operating expenses increased on both a per BOE basis and in total dollars primarily as a result of (i) our increasing emphasis on tertiary operations (see discussion of those expenses under "CO_2 Operations" above), (ii) general cost inflation in our industry, (iii) increased personnel and related costs, (iv) higher fuel and energy costs to operate our properties, (v) increasing lease payments for certain of our tertiary operating facilities, and (vi) higher workover costs. During 2005, operating costs averaged $9.98 per BOE, up from $7.22 per BOE in 2004 and $7.06 per BOE during 2003. Operating expenses on our tertiary operations increased from $19.3 million in 2003 to $24.6 million during 2004 and $40.4 million during 2005, as a result of the increased tertiary activity level. Tertiary operating expenses were particularly impacted by the higher power and energy costs, higher costs for CO_2 and payments on leased facilities and equipment (see "CO_2 Operations" above). We expect this increase in tertiary operating costs to continue and to further increase our cost per BOE as they become a more significant portion of our total production and operations.

Workover expenses increased by over $3.5 million during 2005 as compared to 2004, with over one-half of the increase relating to costs to repair a mechanical failure on one onshore Louisiana well. Workover expenses were also high in 2003 when we spent $2.8 million on two individually significant workovers relating to mechanical failures of two onshore Louisiana wells, plus several smaller workovers.

Production taxes and marketing expenses generally change in proportion to commodity prices and therefore were higher each year along with the increasing commodity prices. The sale of our offshore properties also contributed to the increase in production taxes and marketing expenses on a per BOE basis during 2004 and 2005, as most of our offshore properties were tax exempt. We also recognized incremental transportation expenses paid by us to Genesis as a result of a change in the way we market our crude oil. Beginning in September 2004, we commenced using Genesis as a transporter rather than a purchaser. This incremental transportation cost is approximately $1.0 million per quarter, but is more than offset by higher oil revenue and this change in the way we do business has given us a higher gross margin.

General and Administrative Expenses

During the last three years, general and administrative (G&A) expenses on a per BOE basis have increased from $1.20 per BOE during 2003, to $1.78 per BOE during 2004, to $2.62 per BOE during 2005, increasing even faster than the gross aggregate dollar increases in G&A expense as production has declined each year due primarily to the sale of our offshore properties.

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS EXCEPT PER BOE AND EMPLOYEE DATA	2005	2004	2003
Gross G&A expense	**$ 64,622**	$ 53,658	$ 46,031
Operator overhead charges	**(32,452)**	(28,048)	(26,823)
Capitalized exploration expense	**(5,084)**	(5,072)	(5,507)
	27,086	20,538	13,701
State franchise taxes	**1,454**	923	1,488
Net G&A expense	**$ 28,540**	$ 21,461	$ 15,189
Average G&A expense per BOE	**$ 2.62**	$ 1.78	$ 1.20
Employees as of December 31	**460**	380	374

Gross G&A expenses increased $11.0 million, or 20%, between 2004 and 2005. This increase is generally attributable to higher compensation costs due to additional employees (80 employees were added during 2005), wage increases and $4.1 million of non-cash compensation expense for the amortization of deferred compensation associated with the issuance of restricted stock to officers and directors in 2004 and 2005, as compared to $1.6 million during 2004 (see below). We also incurred approximately $1.4 million to provide food, water, gasoline, and other essential supplies to our employees and charitable organizations in Mississippi and Louisiana following the hurricanes. In addition, we incurred higher professional service and consultant fees primarily related to Sarbanes-Oxley compliance, investigation of hotline reports, and documentation and testing of our new software system that we began using in January 2005, as well as increased maintenance costs as a result of the change to our new software system. These 2005 increases were offset by the absence of approximately $2.4 million of employee severance payments paid in 2004 related to the sale of our offshore properties in July 2004.

Gross G&A expenses increased $7.6 million, or 17%, between 2003 and 2004. The largest component of the increase was approximately $2.4 million of employee severance payments for the offshore professional and technical staff terminated in conjunction with our offshore property sale. We also incurred additional G&A expenses associated with our corporate restructuring in December 2003, compliance with the requirements of the Sarbanes-Oxley Act, the sale of stock by the Texas Pacific Group in March 2004, a provision for potential litigation losses, amortization of restricted stock grants, higher bonus levels for employees than in 2003 due to the strong performance during 2004, and overall increases in most other categories of G&A due to general cost inflation.

From August 2004 through January 2005, we granted a total of 2.3 million shares of restricted stock to our officers and independent directors, generating deferred compensation expense of approximately $23.6 million, the market value of the shares on the date of grant. Approximately 65% of this restricted stock vests over five years and the balance upon retirement (in addition to vesting upon death, disability or a change of control). We are amortizing the non-cash $23.6 million of compensation expense over the five-year vesting period and over the projected retirement date vesting period, expensing approximately $1.6 million during 2004 and $4.1 million during 2005.

Higher operator overhead recovery charges resulting from the incremental development activity helped to partially offset the increase in gross G&A, partially reduced by the impact of the offshore property sale. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of the additional operated wells from acquisitions, additional tertiary operations, and drilling activity during the past year, the amount we recovered as operator overhead charges increased by 5% between 2003 and 2004 and 16% between 2004 and 2005. Capitalized exploration costs decreased in 2004 as a result of the personnel reductions in our offshore area related to the property sale and remained essentially flat in 2005 due to additional personnel and related cost increases. The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 41% increase in net G&A expense between 2003 and 2004 and a 33% increase between 2004 and 2005. The increase was even higher on a per BOE basis as a result of lower production, primarily related to the offshore property sale.

Interest and Financing Expenses

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS EXCEPT PER BOE DATA	2005	2004	2003
Cash interest expense	**$ 18,800**	$ 18,506	$ 21,950
Non-cash interest expense	**827**	962	1,251
Less: Capitalized interest	**(1,649)**	—	—
Interest expense	**$ 17,978**	$ 19,468	$ 23,201
Interest and other income	**$ 3,218**	$ 2,388	$ 1,573
Average net cash interest expense per BOE[(1)]	**$ 1.28**	$ 1.34	$ 1.61
Average debt outstanding	**$248,825**	$270,770	$341,496
Average interest rate[(2)]	**7.6%**	6.8%	6.4%

(1) Cash interest expense less capitalized interest and other income on a BOE basis.

(2) Includes commitment fees but excludes amortization of debt issue costs.

Interest expense for 2005 decreased from 2004 levels primarily due capitalized interest of $1.6 million relating to the construction of our CO_2 pipeline to East Mississippi. As a result of the lower production because of the 2004 offshore sale and production deferred as a result of the two hurricanes, interest expense on a per BOE basis was not as positive as it was on an absolute basis.

Interest expense for 2004 decreased from 2003 levels primarily due to lower average debt levels as a result of our $50 million reduction in debt during 2003 and the payoff of our bank debt in the third quarter of 2004 with the proceeds from our offshore property sale. Our non-cash interest expense in 2004 decreased as a result of the subordinated debt refinancing in March 2003, which eliminated the amortization of discount on our old subordinated debt originally issued in 1998, which was higher than the discount and related amortization on our new subordinated debt issue issued in 2003. Interest and other income increased as a result of the cash generated from the offshore property sale.

Depletion, Depreciation and Amortization ("DD&A")

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS, EXCEPT PER BOE DATA	2005	2004	2003
Depletion and depreciation of oil and natural gas properties	**$88,949**	$88,505	$87,842
Depletion and depreciation of CO_2 assets	**5,334**	4,664	2,542
Asset retirement obligations	**1,682**	2,408	2,852
Depreciation of other fixed assets	**2,837**	1,950	1,472
Total DD&A	**$98,802**	$97,527	$94,708
DD&A per BOE:			
Oil and natural gas properties	**$ 8.34**	$ 7.54	$ 7.16
CO_2 assets and other fixed assets	**0.75**	0.55	0.32
Total DD&A cost per BOE	**$ 9.09**	$ 8.09	$ 7.48

Our proved reserves increased from 128.2 MMBOE as of December 31, 2003, to 129.4 MMBOE as of December 31, 2004, even after adjusting for approximately 16.5 MMBOE of proved reserves, primarily related to the offshore sale that took place in mid-2004. Our proved reserves further increased to 152.6 MMBOE as of December 31, 2005. Reserve quantities and associated production are only one side of the DD&A equation, with capital expenditures less accumulated depletion, asset retirement obligations less related salvage value, and projected future development costs making up the remainder of the calculation.

We adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, and thus our DD&A rate could change significantly in the future. Our DD&A rate on a per BOE basis increased 12% between 2004 and 2005, primarily due to rising costs and increases in capital spending. During 2005, we spent approximately $71.0 million on acquisitions, of which approximately $50.1 million was included in our full cost pool, with the balance becoming part of our unevaluated properties. Due to high commodity prices, the acquisition cost per BOE was around $14.60 per BOE, contributing to the higher DD&A rate. In addition, most of our future development cost estimates on our proved undeveloped reserves have been increased to reflect the rising costs in the industry.

Our DD&A rate on a per BOE basis increased 8% between 2003 and 2004, primarily due to the higher percentage of expenditures on offshore properties during 2003 and the first six months of 2004, which have historically had higher overall finding and development costs, and an increase in certain of our future development cost estimates to reflect the rising costs in the industry. Although the 2004 average DD&A rate was similar to the DD&A rate of $8.00 per BOE during the fourth quarter of 2003, there were significant fluctuations during the year resulting from the offshore sale (as the sales proceeds were credited to the full cost pool) and upward adjustments in future development costs primarily to reflect cost inflation in the industry.

Our DD&A rate for our CO_2 and other fixed assets increased in 2004 and 2005 as a result of the additional cost incurred drilling CO_2 wells during each year and higher associated future development costs, partially offset by an increase in CO_2 reserves from 1.6 Tcf as of December 31, 2003, to 2.7 Tcf as of December 31, 2004, to 4.6 Tcf as of December 31, 2005 (100% working interest basis before amounts attributable to Genesis volumetric production payments – see "CO_2 Operations – CO_2 Resources").

As part of the requirements of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, the fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, with a corresponding capitalized amount. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. On an undiscounted basis, we estimated our retirement obligations as of December 31, 2003, to be $82.7 million, with an

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estimated salvage value of $43.3 million, also on an undiscounted basis. As of December 31, 2004, we estimated our retirement obligations to be $52.1 million ($21.5 million present value), with an estimate salvage value of $43.6 million, the decrease related to the sale of our offshore properties in July 2004. As of December 31, 2005, we estimated our retirement obligations to be $69.1 million ($27.1 million present value), with an estimate salvage value of $50.2 million, the increase related to our increased activity and higher cost estimates due to the inflation in our industry. DD&A is calculated on the increase to oil and natural gas and CO_2 properties, net of estimated salvage value. We also include the accretion of discount on the asset retirement obligation in our DD&A expense.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have any full cost pool ceiling test write-downs in 2003, 2004 or 2005 and do not expect to have any such write-downs in the foreseeable future at current commodity price levels.

Income Taxes

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS, EXCEPT PER BOE AMOUNTS	2005	2004	2003
Current income tax expense (benefit)	**$ 27,177**	$ 22,929	$ (91)
Deferred income tax provision	**54,393**	16,463	26,303
Total income tax provision	**$ 81,570**	$ 39,392	$ 26,212
Average income tax provision per BOE	**$ 7.50**	$ 3.27	$ 2.07
Net effective tax rate	**32.9%**	32.3%	32.7%
Federal tax net operating loss carryforwards	**$ —**	$ —	$ 94,955
Total net deferred tax asset (liability)	**(129,474)**	(71,936)	(43,539)

Our income tax provision for 2004 and 2005 was based on an estimated statutory tax rate of 39%, and for 2003 was based on an estimated statutory tax rate of 38%. Our net effective tax rate was lower than our estimated statutory rates due primarily to our enhanced oil recovery ("EOR") tax credits we earn related to our tertiary operations and to a lesser degree, to a new manufacturing deduction that became allowable in 2005 for oil and gas producing activities covered by the American Jobs Creation Act of 2004. Our current income tax expense represents anticipated cash payment due to alternative minimum taxes. During the third quarter of 2004, we recognized approximately $21.0 million of current income taxes as a result of the sale of our offshore properties, which was a gain for income tax purposes. The taxes on the offshore sale were primarily alternative minimum taxes as we were able to offset the related regular tax with our net operating loss carryforwards.

As of December 31, 2005, we had utilized all of our federal tax net operating loss carryforwards, but had an estimated $42.1 million of enhanced oil recovery credits to carry forward. Since the ability to earn additional enhanced oil recovery credits is reduced or even eliminated based on the level of oil prices, we do not expect to earn any EOR credits during 2006 because of the high oil prices during 2005, which we estimate will raise our effective tax rate. We will be able to utilize the EOR credit carryforwards in the future to reduce our cash taxes. If oil prices remain at current levels or increase further in the future, we will not earn any additional EOR credits and once our existing EOR credits are utilized, our cash taxes will also increase.

Results of Operations on a per BOE Basis

The following table summarizes the cash flow, DD&A and results of operations on a per BOE basis for the comparative periods. Each of the individual components is discussed above.

	YEAR ENDED DECEMBER 31,		
PER BOE DATA	2005	2004	2003
Oil and natural gas revenues	**$50.49**	$36.88	$30.43
Loss on settlements of derivative contracts	**(1.54)**	(7.01)	(4.91)
Lease operating expenses	**(9.98)**	(7.22)	(7.06)
Production taxes and marketing expenses	**(2.54)**	(1.55)	(1.17)
Production netback	**36.43**	21.10	17.29
CO_2 operating margin	**0.54**	0.41	0.51
General and administrative expenses	**(2.62)**	(1.78)	(1.20)
Net cash interest expense	**(1.28)**	(1.34)	(1.61)
Current income taxes and other	**(1.50)**	(1.78)	(0.01)
Changes in assets and liabilities relating to operations	**1.62**	(2.63)	0.62
Cash flow from operations	**33.19**	13.98	15.60
DD&A	**(9.09)**	(8.09)	(7.48)
Deferred income taxes	**(5.00)**	(1.37)	(2.08)
Non-cash derivative adjustments	**(1.12)**	(0.11)	0.28
Changes in assets and liabilities, loss on early retirement of debt, change in accounting principle and other non-cash items	**(2.67)**	2.43	(1.86)
Net income	**$15.31**	$ 6.84	$ 4.46

Market Risk Management

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. The following table presents the carrying and fair values of our debt, along with average interest rates. We had no bank debt outstanding as of December 31, 2005, but had $100 million outstanding at February 15, 2006. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies.

AMOUNTS IN THOUSANDS	MATURITY DATES 2006 – 2010	CARRYING VALUE	FAIR VALUE
Fixed rate debt:			
Senior Subordinated Notes due 2013, net of discount	**$ —**	**$223,591**	**$228,375**
(The interest rate on the subordinated debt is a fixed rate of 7.5%.)			
Senior Subordinated Notes due 2015	**$ —**	**$150,000**	**$152,250**
(The interest rate on the subordinated debt is a fixed rate of 7.5%.)			

From time to time, we enter into various derivative contracts to hedge our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. Historically, we hedged up to 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt. For 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations.

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted proved production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of December 31, 2005, the only derivative contracts we have in place relate to the $248 million acquisition that closed on January 31, 2006, on which we entered into contracts to cover 100% of the estimated proved producing production at the time we signed the purchase and sale agreement. While these derivative contracts related to the acquisition represent less than 6% of our estimated 2006 production, they are intended to help protect our acquisition economics related to the first three years of production from the proved producing reserves that we acquired. These swaps cover 2,200 Bbls/d for 2006 at a price of $59.65 per Bbl; 2,000 Bbls/d for 2007 at a price of $58.93 per Bbl; and 2,000 Bbls/d for 2008 at a price of $57.34 per Bbl.

All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. For a full description of our derivative contract positions at year-end 2005, see Note 9 to the Consolidated Financial Statements.

Effective January 1, 2005, we elected to de-designate our existing derivative contracts as hedges and to account for them as speculative contracts going forward. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. During 2005, we amortized the December 31, 2004, balance in Accumulated Other Comprehensive Loss as that was the remaining life of those contracts. Information regarding our current derivative contract positions and results of our historical derivative activity is included in Note 9 to the Consolidated Financial Statements.

At December 31, 2005, our derivative contracts were recorded at their fair value, which was a net liability of approximately $9.4 million, a larger liability than the $4.9 million fair value liability recorded as of December 31, 2004. This change is the result of higher commodity prices, partially offset by the expiration of several of our derivative contracts during 2005 due to the passage of time. During 2005, we recognized total expense related to our hedge contracts of $29.0 million, consisting of $16.8 million cash payments, $4.5 million of expense relating to market-to-market non-cash adjustments, and $7.7 million of expense related to amortization of Other Comprehensive Loss.

Based on NYMEX crude oil futures prices at December 31, 2005, we would expect to make future cash payments of $10.5 million on our crude oil commodity derivative contracts. If crude oil futures prices were to decline by 10%, we would expect to receive a payment under our crude oil commodity derivative contracts of $3.9 million, and if futures prices were to increase by 10% we would expect to pay $24.8 million. We did not have any NYMEX natural gas commodity derivative contracts outstanding at December 31, 2005.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1 to the Consolidated Financial Statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Reserves

Businesses involved in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full-cost method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full-cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and gas properties, the successful efforts method follows the guidance of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," under which the net book value of assets are measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost method, the full cost pool (net book value of oil and gas properties) is measured against future cash flows discounted at 10% using commodity prices in effect at the end of the reporting period. The financial results for a given period could be substantially different depending on the method of accounting that an oil and gas entity applies.

In our application of full cost accounting for our oil and gas producing activities, we make significant estimates at the end of each period related to accruals for oil and gas revenues, production, capitalized costs and operating expenses. We calculate these estimates with our best available data, which includes, among other things, production reports, price posting, information compiled from daily drilling reports and other internal tracking devices and analysis of historical results and trends. While management is not aware of any required revisions to its estimates, there will likely be future adjustments resulting from such things as changes in ownership interests, payouts, joint venture audits, re-allocations by the purchaser/pipeline, or other corrections and adjustments common in the oil and natural gas industry, many of which will require retroactive application. These types of adjustments cannot be currently estimated or determined and will be recorded in the period during which the adjustment occurs.

Under full cost accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full-cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare the report, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last four years, Denbury's annual revisions to its reserve estimates have averaged approximately 3% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. For instance, between 2001 and 2002, commodity prices rebounded from the prior year's fall, resulting in an increase to our reserve quantities of approximately 3.5 MMBOE. During 2003, 2004 and 2005, the change related to commodity prices was virtually zero, less than in prior years, as prices were relatively high each year-end. These changes in quantities affect our DD&A rate and the combined effect of changes in quantities and commodity prices impacts our full-cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserves quantities would have lowered our fourth quarter 2005 DD&A rate from $9.80 per Bbl to approximately $9.39 per Bbl and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $10.25 per Bbl. Also, reserve quantities and their ultimate values are the primary factors in determining the borrowing base under our bank credit facility and are determined solely by our banks.

There can also be significant questions as to whether reserves are sufficiently supported by technical evidence to be considered proven. In some cases our proven reserves are less than what we believe to exist because additional evidence, including production testing, is required in order to classify the reserves as proven. In other cases, properties such as certain of our potential tertiary recovery projects may not have proven reserves assigned to them primarily because we have not yet completed a specific plan for development or firmly scheduled such development. We have a corporate policy whereby we generally do not book proved undeveloped reserves unless the project has been committed to internally, which normally means it is scheduled within the next one to two years (or at least the commencement of the project is scheduled in the case of longer-term multi-year projects such as waterfloods and tertiary recovery projects). Therefore, particularly with regard to potential reserves from tertiary recovery (our CO_2 operations), there is uncertainty as to whether the reserves should be included as proven or not. We also have a corporate policy whereby proved undeveloped reserves must be economic at long-term historical prices, which are usually significantly less than the year-end prices used in our reserve report. This also can have the effect of eliminating certain projects being included in our estimates of proved reserves, which projects would otherwise be included if undeveloped reserves were determined to be economic solely based on current prices in a high price environment, as was the case during the last three year-ends. (See Depletion, Depreciation and Amortization under Results of Operations above for a further discussion.) All of these factors and the decisions made regarding these issues can have a significant effect on our proven reserves and thus on our DD&A rate, full-cost ceiling test calculation, borrowing base and financial statements.

Asset Retirement Obligations

We have significant obligations related to the plugging and abandonment of our oil and gas wells, and the removal of equipment and facilities from leased acreage and returning such land to its original condition. SFAS No. 143 requires that we estimate the future cost of this obligation, discount it to its present value, and record a corresponding asset and liability in our Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including the ultimate expected cost of the obligation, the expected future date of the required cash payment, and interest and inflation rates. Revisions to these estimates may be required based on changes to cost estimates, the timing of settlement, and changes in legal requirements. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis and an adjustment in our DD&A expense in future periods. See Note 4 to our Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and prior to year-end 2005, net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2005, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet will ultimately be recovered. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not probable. A 1% increase in our effective tax rate would have increased our calculated income tax expense by approximately $2.5 million, $1.2 million, and $0.8 million for the years ended December 31, 2005, 2004 and 2003. See Note 7 to the Consolidated Financial Statements for further information concerning our income taxes.

Oil and Gas Derivative Contracts

We enter into derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for cash flow hedge accounting, the change in fair value of the derivative is recognized in accumulated other comprehensive income (equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective.

Prior to 2005, we applied hedge accounting to our commodity derivative contracts, thereby recording a significant portion of the fair value changes to equity instead of income. We recognized losses on ineffectiveness on our hedges of $282,000 for 2003 and $2.7 million for 2004. We measured and computed hedge effectiveness on a quarterly basis. If a hedging instrument became ineffective, hedge accounting was discontinued and any deferred gains or losses on the cash flow hedge remained in accumulated other comprehensive income until the periods during which the hedges would have otherwise expired. If we determined it probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument were recognized in earnings immediately.

As of January 1, 2005, we abandoned hedge accounting. This means that any changes in the future fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the balance to earnings. While we may experience more volatility in our net income than if we had continued to apply hedge accounting treatment as permitted by SFAS No. 133, we believe that for us the benefits associated with applying hedge accounting do not outweigh the cost, time and effort to comply with hedge accounting. During 2005, we recognized expense of $4.5 million related to changes in the fair market value of our derivative contracts. For our prior two most recently completed fiscal years, if we had not chosen to designate hedge accounting treatment to our oil and natural gas derivative contracts, or if none of our derivative contracts had qualified for hedge accounting treatment, we estimate that our net income would have increased or (decreased) for 2004 and 2003 by approximately $25.0 million and $(7.8 million), respectively.

Use of Estimates

The preparation of financial statements requires us to make other estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable and believe that the ultimate actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties and such risks and uncertainties could cause the actual results to differ materially from our estimates.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), "Share Based Payment," which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their estimated fair values.

We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method described in the statement. Under the modified prospective method, we will apply the standard to new awards granted or modified effective January 1, 2006. Also, we will recognize compensation expense for the unvested portion of awards outstanding as of December 31, 2005 over the remaining service periods. At January 1, 2006, we had $16.6 million of unearned compensation cost related to unvested stock option awards. This compensation cost will be recognized over the remaining vesting period, which is estimated to be approximately $8.0 million during 2006, $5.2 million during 2007, $3.1 million during 2008 and $0.3 million during 2009. These amounts do not include the impact of any new awards granted in 2006.

SFAS No. 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce Denbury's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future; however, it will not have an impact on the Company's overall cash flows.

Forward-Looking Information

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in this Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, mark-to-market values, competition and long-term forecasts of production, finding cost, rates of return, estimated costs, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as plan, estimate, expect, predict, anticipate, projected, should, assume, believe, "target" or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company's oil and natural gas, inaccurate cost estimates, fluctuations in the prices of goods and services, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital or its availability, general economic conditions, competition and government regulations, unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or which are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements.

This Annual Report is not deemed to be soliciting material or to be filed with the Securities and Exchange Commission or subject to the liabilities of Section 18 of the Securities Act of 1934.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A is set forth under Market Risk Management in "Management's Discussion and Analysis of Financial Condition and Results of Operations," appearing on pages 45 through 46.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

Our management, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our system of 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. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) 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 (iii) 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.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Based on our management's assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2005, based on those criteria.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Denbury Resources Inc.:

We have completed integrated audits of Denbury Resources Inc.'s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

In our opinion, the accompanying consolidated financial statements listed in the accompanying index, present fairly, in all material respects, the financial position of Denbury Resources Inc. and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. 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 of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal Control over Financial Reporting

Also, in our opinion, management's assessment, included in the accompanying "Management's Report on Internal Control over Financial Reporting," that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes 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 consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

PricewaterhouseCoopers LLP
Dallas, Texas
March 7, 2006

Report of Independent Registered Public Accounting Firm

To the Stockholders of Denbury Resources Inc.

We have audited the accompanying consolidated statements of operations, cash flows, stockholders' equity and comprehensive income of Denbury Resources Inc. and Subsidiaries (the "Company") for the year ended December 31, 2003. 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 audit.

We conducted our audit in accordance with 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 audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the results of its operations and its cash flows for the year ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements under the caption Asset Retirement Obligations, the Company changed its method of accounting for asset retirement obligations in 2003 as required by Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

Deloitte & Touche LLP

Deloitte & Touche LLP
Dallas, Texas
March 8, 2004

Consolidated Balance Sheets

(IN THOUSANDS, EXCEPT SHARES)	DECEMBER 31, 2005	2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 165,089**	$ 33,039
Short-term investments	**—**	57,171
Accrued production receivable	**65,611**	44,790
Related party receivable – Genesis	**1,312**	745
Trade and other receivables, net of allowance of $289 and $236	**25,887**	10,963
Deferred tax asset	**41,284**	25,189
Derivative assets	**—**	949
Total current assets	**299,183**	172,846
PROPERTY AND EQUIPMENT		
Oil and natural gas properties (using full cost accounting)		
Proved	**1,669,579**	1,326,401
Unevaluated	**46,597**	20,253
CO_2 properties and equipment	**210,046**	132,685
Other	**34,647**	25,929
Less accumulated depletion and depreciation	**(804,899)**	(707,906)
Net property and equipment	**1,155,970**	797,362
Investment in Genesis	**10,829**	6,791
Deposits on property acquisitions	**26,425**	4,507
Other assets	**12,662**	11,200
TOTAL ASSETS	**$1,505,069**	$ 992,706
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**$ 104,840**	$ 49,429
Oil and gas production payable	**41,821**	24,856
Derivative liabilities	**2,759**	5,815
Deferred revenue – Genesis	**4,070**	2,431
Short-term capital lease obligations – Genesis	**574**	375
Total current liabilities	**154,064**	82,906
LONG-TERM LIABILITIES		
Capital lease obligations – Genesis	**5,870**	4,184
Long-term debt, net of discount	**373,591**	223,397
Asset retirement obligations	**25,297**	18,944
Derivative liabilities	**6,624**	—
Deferred revenue – Genesis	**33,023**	23,378
Deferred tax liability	**170,758**	97,125
Other	**2,180**	1,100
Total long-term liabilities	**617,343**	368,128
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
STOCKHOLDERS' EQUITY		
Preferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding	**—**	—
Common stock, $.001 par value, 250,000,000 shares authorized; 115,038,531, and 56,607,877 shares issued at December 31, 2005 and 2004, respectively	**115**	57
Paid-in capital in excess of par	**461,112**	441,023
Deferred compensation	**(17,829)**	(21,678)
Retained earnings	**295,575**	129,104
Accumulated other comprehensive loss	**—**	(4,788)
Treasury stock, at cost, 340,337 and 93,072 shares at December 31, 2005 and 2004, respectively	**(5,311)**	(2,046)
Total stockholders' equity	**733,662**	541,672
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$1,505,069**	$ 992,706

See Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

(IN THOUSANDS, EXCEPT PER SHARE DATA)	YEAR ENDED DECEMBER 31, 2005	2004	2003
REVENUES			
Oil, natural gas and related product sales			
Unrelated parties	**$544,408**	$381,253	$336,521
Related party – Genesis	**4,647**	63,524	48,942
CO_2 sales and transportation fees			
Unrelated parties	**1,538**	1,183	7,512
Related party – Genesis	**6,581**	5,093	676
Loss on effective hedge contracts	**—**	(70,469)	(62,210)
Interest income and other	**3,218**	2,388	1,573
Total revenues	**560,392**	382,972	333,014
EXPENSES			
Lease operating expenses	**108,550**	87,107	89,439
Production taxes and marketing expenses	**23,553**	17,569	14,819
Transportation expense – Genesis	**4,029**	1,168	—
CO_2 operating expenses	**2,251**	1,338	1,710
General and administrative	**28,540**	21,461	15,189
Interest, net of amounts capitalized of $1,649 in 2005	**17,978**	19,468	23,201
Loss on early retirement of debt	**—**	—	17,629
Depletion, depreciation and accretion	**98,802**	97,527	94,708
Commodity derivative expense (income)	**28,962**	15,358	(3,578)
Total expenses	**312,665**	260,996	253,117
Equity in net income (loss) of Genesis	**314**	(136)	256
Income before income taxes	**248,041**	121,840	80,153
Income tax provision (benefit)			
Current income taxes	**27,177**	22,929	(91)
Deferred income taxes	**54,393**	16,463	26,303
Income before cumulative effect of change in accounting principle	**166,471**	82,448	53,941
Cumulative effect of change in accounting principle, net of income taxes of $1,600	**—**	—	2,612
NET INCOME	**$166,471**	$ 82,448	$ 56,553
NET INCOME PER SHARE – BASIC			
Income before cumulative effect of change in accounting principle	**$ 1.49**	$ 0.75	$ 0.50
Cumulative effect of change in accounting principle	—	—	0.02
Net income per common share – basic	**$ 1.49**	$ 0.75	$ 0.52
NET INCOME PER SHARE – DILUTED			
Income before cumulative effect of change in accounting principle	**$ 1.39**	$ 0.72	$ 0.49
Cumulative effect of change in accounting principle	—	—	0.02
Net income per common share – diluted	**$ 1.39**	$ 0.72	$ 0.51
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING			
Basic	**111,743**	109,741	107,763
Diluted	**119,634**	114,603	110,928

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2005	2004	2003
CASH FLOW FROM OPERATING ACTIVITIES:			
Net income	**$ 166,471**	$ 82,448	$ 56,553
Adjustments needed to reconcile to net cash flow provided by operations:			
Depreciation, depletion and accretion	**98,802**	97,527	94,708
Deferred income taxes	**54,393**	16,463	26,303
Deferred revenue – Genesis	**(3,080)**	(2,399)	(322)
Deferred compensation – restricted stock	**4,121**	1,601	—
Loss on early retirement of debt	**—**	—	17,629
Non-cash hedging adjustments	**12,201**	1,270	(3,578)
Current income tax benefit from stock options	**9,218**	1,706	—
Amortization of debt issue costs and other	**1,257**	1,577	1,121
Cumulative effect of change in accounting principle	**—**	—	(2,612)
Changes in assets and liabilities relating to operations:			
Accrued production receivable	**(21,388)**	(19,776)	(3,079)
Trade and other receivables	**(14,924)**	7,475	(1,234)
Derivative assets and liabilities	**—**	(7,519)	—
Other assets	**129**	(166)	7
Accounts payable and accrued liabilities	**38,202**	(10,522)	8,862
Oil and gas production payable	**16,966**	2,641	4,906
Other liabilities	**(1,408)**	(3,674)	(1,649)
NET CASH PROVIDED BY OPERATING ACTIVITIES	**360,960**	168,652	197,615
CASH FLOW USED FOR INVESTING ACTIVITIES:			
Oil and natural gas expenditures	**(308,366)**	(167,001)	(146,596)
Acquisitions of oil and gas properties	**(70,870)**	(11,069)	(11,848)
Increase in accrual for capital expenditures	**18,196**	—	—
Investment in Genesis	**(4,257)**	—	(5,026)
Acquisition of CO_2 assets and capital expenditures	**(78,726)**	(50,265)	(22,673)
Net purchases of other assets	**(6,441)**	(5,210)	(2,192)
Deposits on acquisitions	**(21,917)**	(4,507)	—
Increase in restricted cash	**(249)**	(542)	(848)
Purchases of short-term investments	**—**	(76,517)	—
Sales of short-term investments	**57,133**	19,350	—
Net proceeds from CO_2 production payment – Genesis	**14,363**	4,636	23,895
Proceeds from sales of oil and gas properties and equipment	**17,447**	10,042	29,410
Sale of Denbury Offshore, Inc.	**—**	187,533	—
NET CASH USED FOR INVESTING ACTIVITIES	**(383,687)**	(93,550)	(135,878)
CASH FLOW FROM FINANCING ACTIVITIES:			
Bank repayments	**(64,800)**	(88,000)	(160,000)
Bank borrowings	**64,800**	13,000	85,000
Payments on capital lease obligations – Genesis	**(521)**	(32)	—
Repayment of subordinated debt obligations, including redemption premium	**—**	—	(209,000)
Issuance of subordinated debt, net of discount	**150,000**	—	223,054
Issuance of common stock	**12,392**	13,168	5,537
Purchase of treasury stock	**(5,119)**	(3,977)	(1,268)
Costs of debt financing	**(1,975)**	(410)	(4,812)
NET CASH PROVIDED BY (USED FOR) FINANCING ACTIVITIES	**154,777**	(66,251)	(61,489)
NET INCREASE IN CASH AND CASH EQUIVALENTS	**132,050**	8,851	248
Cash and cash equivalents at beginning of year	**33,039**	24,188	23,940
Cash and cash equivalents at end of year	**$ 165,089**	$ 33,039	$ 24,188

See Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Stockholders' Equity

(DOLLAR AMOUNTS IN THOUSANDS)	COMMON STOCK ($.001 PAR VALUE) SHARES	AMOUNT	PAID-IN CAPITAL IN EXCESS OF PAR
BALANCE – DECEMBER 31, 2002	53,539,329	$ 54	$395,906
Repurchase of common stock	—	—	—
Issued pursuant to employee stock purchase plan	94,968	—	1,174
Issued pursuant to employee stock option plan	550,090	—	3,213
Issued pursuant to directors' compensation plan	5,655	—	69
Tax benefit from stock options	—	—	1,347
Derivative contracts, net	—	—	—
Net income	—	—	—
BALANCE – DECEMBER 31, 2003	54,190,042	54	401,709
Repurchase of common stock	—	—	—
Issued pursuant to employee stock purchase plan	—	—	396
Issued pursuant to employee stock option plan	1,264,284	2	10,737
Issued pursuant to directors' compensation plan	3,551	—	82
Restricted stock grants	1,150,000	1	23,278
Amortization of deferred compensation	—	—	—
Tax benefit from stock options	—	—	4,821
Derivative contracts, net	—	—	—
Unrealized loss on available-for-sale securities	—	—	—
Net income	—	—	—
BALANCE – DECEMBER 31, 2004	56,607,877	57	441,023
Repurchase of common stock	**—**	**—**	**—**
Issued pursuant to employee stock purchase plan	**—**	**—**	**887**
Issued pursuant to employee stock option plan	**949,051**	**1**	**9,650**
Issued pursuant to directors' compensation plan	**3,502**	**—**	**119**
Restricted stock grants	**10,000**	**—**	**272**
Two-for-one stock split	**57,468,101**	**57**	**(57)**
Amortization of deferred compensation	**—**	**—**	**—**
Tax benefit from stock options	**—**	**—**	**9,218**
Derivative contracts, net	**—**	**—**	**—**
Unrealized gain on available-for-sale securities	**—**	**—**	**—**
Net income	**—**	**—**	**—**
BALANCE – DECEMBER 31, 2005	**115,038,531**	**$115**	**$461,112**

See Notes to Consolidated Financial Statements.

RESTRICTED STOCK DEFERRED COMPENSATION	RETAINED EARNINGS (ACCUMULATED DEFICIT)	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TREASURY STOCK (AT COST)		TOTAL STOCKHOLDERS' EQUITY
			SHARES	AMOUNT	
$ —	$ (9,875)	$(19,288)	—	$ —	$366,797
—	—	—	100,000	(1,276)	(1,276)
—	(22)	—	(91,838)	1,172	2,324
—	—	—	—	—	3,213
—	—	—	—	—	69
—	—	—	—	—	1,347
—	—	(7,825)	—	—	(7,825)
—	56,553	—	—	—	56,553
—	46,656	(27,113)	8,162	(104)	421,202
—	—	—	200,000	(3,977)	(3,977)
—	—	—	(115,090)	2,035	2,431
—	—	—	—	—	10,739
—	—	—	—	—	82
(23,279)	—	—	—	—	—
1,601	—	—	—	—	1,601
—	—	—	—	—	4,821
—	—	22,349	—	—	22,349
—	—	(24)	—	—	(24)
—	82,448	—	—	—	82,448
(21,678)	129,104	(4,788)	93,072	(2,046)	541,672
—	**—**	**—**	**142,287**	**(5,119)**	**(5,119)**
—	**—**	**—**	**(80,869)**	**1,854**	**2,741**
—	**—**	**—**	**—**	**—**	**9,651**
—	**—**	**—**	**—**	**—**	**119**
(272)	**—**	**—**	**—**	**—**	**—**
—	**—**	**—**	**185,847**	**—**	**—**
4,121	**—**	**—**	**—**	**—**	**4,121**
—	**—**	**—**	**—**	**—**	**9,218**
—	**—**	**4,764**	**—**	**—**	**4,764**
—	**—**	**24**	**—**	**—**	**24**
—	**166,471**	**—**	**—**	**—**	**166,471**
$(17,829)	**$295,575**	**$ —**	**340,337**	**$(5,311)**	**$733,662**

Consolidated Statements of Comprehensive Income

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2005	2004	2003
NET INCOME	**$166,471**	$ 82,448	$ 56,553
Other comprehensive income (loss), net of tax:			
Change in fair value of derivative contracts, net of tax of ($19,328) and ($26,969), respectively	**—**	(31,535)	(44,002)
Reclassification adjustments related to settlements of derivative contracts, net of tax of $2,920, $33,025 and $22,173, respectively	**4,764**	53,884	36,177
Unrealized gain (loss) on securities available for sale, net of tax of $15 and ($15), respectively	**24**	(24)	—
COMPREHENSIVE INCOME	**$171,259**	$104,773	$ 48,728

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc. is a Delaware corporation, organized under *Delaware General Corporation Law,* engaged in the acquisition, development, operation and exploration of oil and natural gas properties. Denbury has one primary business segment, which is the exploration, development and production of oil and natural gas in the U.S. Gulf Coast region. We also own the rights to a natural source of carbon dioxide (CO_2) reserves that we use for injection in our tertiary oil recovery operations. We also sell some of the CO_2 we produce to Genesis (see Note 3) and to third party industrial users.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with generally accepted accounting principles (GAAP) and include the accounts of Denbury and its subsidiaries, all of which are wholly owned. In 2002, one of our subsidiaries acquired the general partner of Genesis Energy, L.P. (Genesis), a publicly traded master limited partnership. During 2003, we acquired additional Genesis limited partnership units, increasing our ownership interest in Genesis from 2% to 9.25%. We account for our ownership interest in Genesis under the equity method of accounting. Even though we have significant influence over the limited partnership in our role as general partner, because our control is limited by the general partnership agreement we do not consolidate Genesis. See Note 3 for more information regarding our related party transactions with Genesis and summary financial information. All material intercompany balances and transactions have been eliminated. We have evaluated our consolidation of variable interest entities in accordance with FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," and have concluded that we do not have any variable interest entities that would require consolidation.

Effective December 29, 2003, Denbury Resources Inc. changed its corporate structure to a holding company format. The purposes of creating the holding company structure were to better reflect the operating practices and methods of Denbury, to improve its economics, and to provide greater administrative and operational flexibility. As part of this restructure, Denbury Resources Inc. (predecessor entity) merged into a newly formed limited liability company and survived as Denbury Onshore, LLC, a Delaware limited liability company and an indirect subsidiary of the newly formed holding company, Denbury Holdings, Inc. Denbury Holdings, Inc. subsequently assumed the name Denbury Resources Inc. (new entity). The reorganization was structured as a tax-free reorganization to Denbury's stockholders and all outstanding capital stock of the original public company was automatically converted into the identical number of and type of shares of the new public holding company. Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company remained publicly traded under the same symbol (DNR) on the New York Stock Exchange.

Stock Split

On October 19, 2005, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, received one additional share of Denbury common stock for each share of common stock held at that time. Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock split, except for our December 31, 2004 balance sheet, which has not been retroactively adjusted to reflect the stock split.

Oil and Natural Gas Operations

A) Capitalized Costs. We follow the full-cost method of accounting for oil and natural gas properties. Under this method, all costs related to acquisitions, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells and general and administrative expenses directly related to exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

B) Depletion and Depreciation. The costs capitalized, including production equipment, are depleted or depreciated on the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units based upon the relative energy content which is six thousand cubic feet of natural gas to one barrel of crude oil.

C) Asset Retirement Obligations. On January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant. Prior to the adoption of this new standard, we recognized a provision for our asset retirement obligations each period as part of our depletion and depreciation calculation, based on the unit-of-production method. See Note 4 for more information regarding our change in accounting related to the adoption of SFAS No. 143.

D) Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as the sum of (i) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at 10%), based on unescalated period-end oil and natural gas prices; (ii) plus the cost of properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (iv) less related income tax effects. The cost center ceiling test is prepared quarterly.

E) Joint Interest Operations. Substantially all of our oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only Denbury's proportionate interest in such activities and any amounts due from other partners are included in trade receivables.

F) Proved Reserves. See Note 14 for information on our proved oil and natural gas reserves and the basis on which they are recorded.

Property and Equipment – Other

Other property and equipment, which includes furniture and fixtures, vehicles, computer equipment and software, and capitalized leases, is depreciated principally on a straight-line basis over estimated useful lives. Estimated useful lives are generally as follows: vehicles and furniture and fixtures – 5 to 10 years; and computer equipment and software – 3 to 5 years.

Leased property meeting certain capital lease criteria is capitalized and the present value of the related lease payments is recorded as a liability. Amortization of capitalized leased assets is computed using the straight-line method over the shorter of the estimated useful life or the initial lease term.

Revenue Recognition

Revenue is recognized at the time oil and natural gas is produced and sold. Any amounts due from purchasers of oil and natural gas are included in accrued production receivable.

We follow the sales method of accounting for our oil and natural gas revenue, whereby we recognize revenue on all oil or natural gas sold to our purchasers regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2005 and 2004, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

We recognize revenue and expenses of purchased producing properties at the time we assume effective control, commencing from either the closing or purchase agreement date, depending on the underlying terms and agreements. We follow the same methodology in reverse when we sell properties by recognizing revenue and expenses of the sold properties until either the closing or purchase agreement date, depending on the underlying terms and agreements.

Derivative Instruments and Hedging Activities

We enter into derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts and accordingly de-designated our derivative instruments from hedge accounting treatment. As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change. Additionally, the balance remaining in accumulated comprehensive income at December 31, 2004, related to the de-designated derivative contracts was amortized over the remaining life of the contracts, all of which expired in 2005.

Financial Instruments with Off-Balance-Sheet Risk and Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, trade and accrued production receivables and the derivative hedging instruments discussed above. Our cash equivalents and short-term investments represent high-quality securities placed with various investment-grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. Also, most of our significant purchasers are large companies with excellent credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our derivative hedging contracts through formal credit policies, monitoring procedures and diversification. There are no margin requirements with the counterparties of our derivative contracts.

CO_2 Operations

We own and produce CO_2 reserves that are used for our own tertiary oil recovery operations, and in addition, we sell a portion to Genesis and to other third party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. CO_2 used for our own tertiary oil recovery operations is not recorded as revenue in the Consolidated Statements of Operations. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes used for our own use. The expenses related to third party sales are recorded in "CO_2 operating expenses" and the expenses related to our own uses are recorded in "Lease operating expenses" in the Consolidated Statements of Operations. We capitalize acquisitions and the costs of exploring and developing CO_2 reserves. The costs capitalized are depleted or depreciated on the unit-of-production method, based on proved CO_2 reserves as determined by independent engineers. We evaluate our CO_2 assets for impairment by comparing our expected future revenues from these assets to their net carrying value.

Cash Equivalents

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase.

Short-term Investments

Our short-term investments consist primarily of investment grade debt securities that are classified as "available-for-sale" in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Available-for-sale securities are stated at fair value, based on quoted market prices, with the unrealized gain or loss, net of tax, reported in other comprehensive income. Premiums and discounts are amortized or accreted into earnings over the life of the related security. Dividend and interest income is recognized when earned. We have no investments that are considered to be trading securities.

During the first nine months of 2005, we sold all of our available-for-sale securities.

Restricted Cash and Investments

At December 31, 2005 and 2004, we had approximately $6.7 million and $6.4 million, respectively, of restricted cash and investments held in escrow accounts for future site reclamation costs. These balances are recorded at amortized cost and are included in "Other assets" in the Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2005 and 2004, was virtually the same as amortized cost.

Net Income Per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from stock options, restricted stock and any other outstanding convertible securities.

For each of the three years in the period ended December 31, 2005, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share. The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share computations:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Weighted average common shares – basic	**111,743**	109,741	107,763
Potentially dilutive securities:			
Stock options	**6,931**	4,827	3,165
Restricted stock	**960**	35	—
Weighted average common shares – diluted	**119,634**	114,603	110,928

The weighted average common shares – basic amount in 2005 and 2004, excludes 2.0 million and 2.3 million shares of non-vested restricted stock, respectively, that is subject to future time vesting requirements. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share. For purposes of calculating weighted average common shares – diluted, the non-vested restricted stock is included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity. The restricted shares were issued in August 2004 through January 2005 and have been included in the calculation for the periods they were outstanding. These shares may result in greater dilution in future periods, depending on the market price of our common stock during those periods. We excluded stock options representing 184,000 shares in 2005, 80,000 shares in 2004 and 2.0 million shares in 2003 from our diluted shares outstanding because their inclusion would be antidilutive, as their exercise prices exceeded the average market price of our common stock during the respective periods.

Stock-Based Compensation

We issue stock options and restricted stock to our employees and directors under our stock option plans, which are described more fully in Note 8. We account for our stock-based employee compensation utilizing the recognition and measurement principles of Accounting Principles Board Opinion 25 (APB 25), "Accounting for Stock Issued to Employees," and its related interpretations. Under these principles, no compensation expense for stock options is reflected in net income as long as the stock options have an exercise price equal to the quoted market price of the underlying common stock on the date of grant. For restricted stock grants, we recognize compensation expense equal to the intrinsic value of the stock on the date of grant pro-rata over the applicable vesting periods. The following table illustrates the effect on net income and net income per common share if we had applied the fair value provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148, in accounting for our stock-based compensation.

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS, EXCEPT PER SHARE DATA)	2005	2004	2003
NET INCOME:			
Net income, as reported	**$166,471**	$82,448	$56,553
Add: Stock-based compensation included in reported net income, net of related tax effects	**2,765**	977	—
Less: Stock-based compensation expense applying fair value based method, net of related tax effects	**8,425**	3,713	2,995
Pro forma net income	**$160,811**	$79,712	$53,558
NET INCOME PER COMMON SHARE			
As reported:			
Basic	**$1.49**	$0.75	$0.52
Diluted	**1.39**	0.72	0.51
Pro forma:			
Basic	**$1.44**	$0.73	$0.50
Diluted	**1.36**	0.69	0.49

The weighted average fair value of options granted using the Black-Scholes option pricing model and the weighted average assumptions used in determining those fair values are as follows:

	2005	2004	2003
Weighted average fair value of options granted	**$6.94**	$3.22	$3.01
Risk free interest rate	**3.80%**	3.34%	2.94%
Expected life	**5 years**	5 years	5 years
Expected volatility	**42.6%**	46.8%	59.6%
Dividend yield	**—**	—	—

Income Taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include (i) the fair value of financial derivative instruments, (ii) the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows therefrom and ceiling test, (iii) accruals related to oil and gas production and revenues, capital expenditures and lease operating expenses, (iv) the estimated costs and timing of future asset retirement obligations, and (v) estimates made in the calculation of income taxes. While management is not aware of any significant revisions to any of its estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), "Share Based Payment," which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their estimated fair values.

We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method described in the statement. Under the modified prospective method, we will apply the standard to new awards granted or modified effective January 1, 2006. Also, we will recognize compensation expense for the unvested portion of awards outstanding as of December 31, 2005 over the remaining service periods. At January 1, 2006, we had $16.6 million of unearned compensation cost related to unvested stock option awards. This compensation cost will be recognized over the remaining vesting period, which is estimated to be approximately $8.0 million during 2006, $5.2 million during 2007, $3.1 million during 2008 and $0.3 million during 2009. These amounts do not include the impact of any new awards granted in 2006.

SFAS No. 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce Denbury's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future; however, it will not have an impact on the Company's overall cash flows.

Note 2. Acquisitions and Divestitures

2006 Acquisition of Producing and Tertiary Oil Properties

In November 2005, we entered into an agreement to acquire oil properties located in Mississippi and Alabama for $248 million. At December 31, 2005, we had $25 million of earnest money deposited for this pending acquisition, which is included in "Deposits on property acquisitions" in our Consolidated Balance Sheet. The acquisition closed in January of 2006. See Note 13, "Subsequent Events."

2005 Acquisitions of Producing and Tertiary Oil and Gas Properties

Our acquisitions in 2005 included the purchase of additional interest and acreage in the Barnett Shale area ($34.2 million), additional interest in the Eucutta Field ($8.0 million), and the purchase of two oil fields that may be potential tertiary flood candidates in the future, Lake St. John ($16.1 million) and Cranfield ($1.1 million).

Sale of Denbury Offshore, Inc.

On July 20, 2004, we closed the sale of Denbury Offshore, Inc., a subsidiary that held our offshore assets, for $200 million (before adjustments) to Newfield Exploration Company. The sale price was based on the asset value of the offshore assets as of April 1, 2004, which means that the net operating cash flow (defined as revenue less operating expenses and capital expenditures) from these properties which we received between April 1 and closing, as well as expenses of the sale and other contractual adjustments, reduced the purchase price to approximately $187 million. We excluded from the sale a discovery well drilled at High Island A-6 during 2004, and certain deep rights at West Delta 27 that we sold for $1.8 million in December 2004, but retained a carried interest in a deep exploratory well.

Our financial results for 2004 include production, revenues, operating expenses, and capital expenditures of the offshore properties through July 19, 2004. Revenues of Denbury Offshore, Inc. included in our 2004 results were $62.6 million. We recorded the proceeds from the sale as a reduction to our full cost pool. We paid approximately $21 million of current income taxes relating to the sale and paid approximately $2.4 million of employee severance costs in 2004. We used $85 million of the sales proceeds to retire our bank debt.

Our offshore properties made up approximately 12.5% of our year-end 2003 proved reserves (approximately 96 Bcfe as of December 31, 2003) and represented approximately 25% of our 2004 second quarter production (9,114 BOE/d).

2003 Property Sales

In February 2003, we sold Laurel Field, acquired in an acquisition from COHO Resources during 2002, for $25.9 million and other consideration which included an interest in Atchafalaya Bay Field (where we already owned an interest) and seismic over that area. At December 31, 2002, Laurel Field had approximately 7.4 MMBbls of proved reserves. In March 2003, we sold the Bentonia and Glazier fields for approximately $1.6 million. The proceeds from the sale of Laurel Field were used to reduce our bank debt.

Note 3. Related Party Transactions – Genesis

Interest in and Transactions with Genesis

On May 14, 2002, a newly formed subsidiary of Denbury acquired Genesis Energy, L.L.C. (which was subsequently converted to Genesis Energy, Inc.), the general partner of Genesis, a publicly traded master limited partnership, for total consideration, including expenses and commissions, of approximately $2.2 million. Genesis' primary business activities include gathering, marketing and transportation of crude oil and natural gas, and wholesale marketing of CO_2, primarily in Mississippi, Texas, Alabama and Florida. In November 2003, through our subsidiary general partner, we purchased an additional 689,000 partnership common units and 14,000 general partner units of Genesis for $7.15 per unit, with an aggregate purchase price of approximately $5.0 million. With these additional units, our ownership interest increased to approximately 9.25% (2.0% general partner ownership and 7.25% limited partner ownership). In December 2005, Genesis issued additional common units in a public offering. Our subsidiary Genesis Energy, Inc. acquired an additional 91,694 general partner units and 330,630 common units in this offering for $4.3 million, which maintained our same ownership interest of approximately 9.25%.

We are accounting for our 9.25% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Our equity in Genesis' net income (loss) for 2005 was $314,000, for 2004 was ($136,000), and for 2003 was $256,000, representing 2% of Genesis' net income (loss) for the periods from January 1, 2003, through October 31, 2003, and 9.25% of Genesis' net income (loss) for the periods from November 1, 2003, through December 31, 2005. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which consisted of $10.1 million in letters of credit at December 31, 2005. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. Our investment in Genesis of $11.5 million exceeded our percentage of net equity in the limited partnership at the time of acquisition by approximately $2.2 million, which represents goodwill and is not subject to amortization. The fair value of our investment in Genesis was $15.2 million at December 31, 2005, based on quoted market values.

Oil Sales and Transportation Services

Prior to September 2004, including the period prior to our investment in Genesis, we sold certain of our oil production to Genesis. Beginning in September 2004, we discontinued most of our direct oil sales to Genesis and began to transport our crude oil using Genesis' Mississippi common carrier pipeline to a sales point where it is sold to third party purchasers. For these transportation services, we pay Genesis a fee for the use of their pipeline and trucking services. For 2005 and 2004, we expensed $4.0 and $1.2 million for these transportation services. We recorded oil sales to Genesis of $4.6 million, $63.5 million and $48.9 million for the years ended December 31, 2005, 2004, and 2003, respectively. Denbury received other miscellaneous payments from Genesis, including $120,000 in each year (2005, 2004 and 2003) in director fees for certain executive officers of Denbury that are board members of Genesis, and $528,000 in 2005, $508,000 in 2004 and $57,000 in 2003 of pro rata dividend distributions from Genesis.

Transportation Leases

In late 2004 and early 2005, we entered into pipeline transportation agreements with Genesis to transport in its pipelines our crude oil from Olive, Brookhaven and McComb Fields in Southwest Mississippi to Genesis' main crude oil pipeline in order to improve our ability to market our crude oil, and to transport CO_2 from our main CO_2 pipeline to Brookhaven Field for our tertiary operations. As part of these arrangements, we entered into three transportation agreements. The first agreement, entered into in November 2004, was to transport crude oil from Olive Field. This agreement is for 10 years and has a minimum payment of approximately $18,000 per month. In December 2004, we entered into the second transportation agreement to transport CO_2 to Brookhaven Field in Southwest Mississippi. This agreement is for an eight-year period and has minimum payments of approximately $49,000 per month. In January 2005, we entered into a third transportation agreement to transport crude oil from Brookhaven field. This agreement is for 10 years and has a minimum payment of approximately $32,000 per month. The minimum monthly payment in each agreement will increase for any volumes transported in excess of a stated monthly volume in the contract. Currently, we are paying the minimum on each contract. Genesis operates and maintains these pipelines at its own expense.

We have accounted for these agreements as capital leases. The pipelines held under these capital leases are classified as property and equipment and are amortized using the straight-line method over the lease terms. Lease amortization is included in depreciation expense. The related obligations are recorded as debt. At December 31, 2005, we had $6.4 million recorded as debt, of which $574,000 was current. At December 31, 2004, we had $4.6 million recorded as debt, of which $375,000 was current.

CO_2 Volumetric Production Payments

In November 2003, we sold 167.5 Bcf of CO_2 to Genesis for $24.9 million ($23.9 million as adjusted for interim cash flows from the September 1, 2003, effective date and for transaction costs) under a volumetric production payment ("VPP"), and assigned to Genesis three of our existing long-term commercial CO_2 supply agreements with our industrial customers. These industrial contracts represented approximately 60% of our then current industrial CO_2 sales volumes. Pursuant to the VPP, Genesis may take up to 52.5 MMcf/d of CO_2 through 2009, 43.0 MMcf/d from 2010 through 2012, and 25.2 MMcf/d to the end of the term.

On August 26, 2004, we closed on another transaction with Genesis, selling to them a 33.0 Bcf volumetric production payment ("VPPII") of CO_2 for $4.8 million ($4.6 million as adjusted for interim cash flows from the July 1 effective date and for transaction costs) along with a related long-term supply agreement with an industrial customer. Pursuant to the VPPII, Genesis may take up to 9 MMcf/d of CO_2 to the end of the contract term.

In October 2005, we sold a third CO_2 volumetric production payment ("VPP III") to Genesis. Under the VPP III, we sold 80.0 Bcf of CO_2 for $14.7 million ($14.4 million as adjusted for interim cash flows from the September 1 effective date and for transaction costs), and assigned to Genesis two of our existing long-term commercial CO_2 supply agreements with our industrial customers. Pursuant to the VPP III, Genesis may take up to 27.4 MMcf/d to the end of the contract term.

We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and will recognize such revenue as CO_2 is delivered during the term of the three volumetric production payments. At December 31, 2005, 2004 and 2003, \$37.1 million, \$25.8 million and \$23.6 million, respectively, was recorded as deferred revenue of which \$4.1 million, \$2.4 million and \$2.1 million was included in current liabilities at December 31, 2005, 2004 and 2003, respectively. During 2005, 2004 and 2003, we recognized deferred revenue of \$3.1 million, \$2.4 million and \$0.3 million, respectively, for deliveries under these volumetric production payments. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately \$0.17 per Mcf during 2005 and \$0.16 per Mcf during 2004 and 2003, of CO_2 delivered to their industrial customers, which resulted in \$3.5 million, \$2.7 million and \$0.4 million in revenue to Denbury for the years ended December 31, 2005, 2004 and 2003, respectively. At December 31, 2005 and 2004, we had a net receivable from Genesis of \$1.3 million and \$0.7 million, respectively, associated with all of the transactions described above.

Summarized Financial Information of Genesis Energy, L.P.

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Revenues	**\$1,078,739**	\$927,143	\$657,897
Cost of sales	**1,057,621**	908,804	644,157
Other expenses	**17,429**	19,288	14,159
Income (loss) from continuing operations before cumulative effect adjustment	**3,689**	(949)	(419)
Income (loss) from discontinued operations	**312**	(463)	13,741
Cumulative effect adjustment	**(586)**	—	—
Net income (loss)	**\$ 3,415**	\$ (1,412)	\$ 13,322

	DECEMBER 31,	
(IN THOUSANDS)	2005	2004
Current assets	**\$ 90,449**	\$ 77,396
Non-current assets	**91,328**	65,758
Total assets	**\$181,777**	\$143,154
Current liabilities	**\$ 92,611**	\$ 81,938
Non-current liabilities	**955**	15,460
Partners' capital	**88,211**	45,756
Total liabilities and partners' capital	**\$181,777**	\$143,154

Note 4. Asset Retirement Obligations

On January 1, 2003, we adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil and natural gas wells, removal of equipment and facilities from leased acreage and land restoration. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Prior to the adoption of this new standard, we recognized a provision for our asset retirement obligations each period as part of our depletion and depreciation calculation, based on the unit-of-production method. The adoption of SFAS No. 143 on January 1, 2003, required us to record a \$2.6 million gain as a cumulative effect adjustment of a change in accounting principle, net of taxes.

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2005 and 2004.

	YEAR ENDED DECEMBER 31,	
(IN THOUSANDS)	2005	2004
Beginning asset retirement obligation	**$21,540**	$ 43,812
Liabilities incurred during period	**3,091**	3,206
Revisions in estimated cash flows	**1,765**	—
Liabilities settled during period	**(990)**	(2,549)
Liabilities sold during period	**—**	(25,337)
Accretion expense	**1,682**	2,408
Ending asset retirement obligation	**$27,088**	$ 21,540

Liabilities sold during the 2004 period primarily represent the asset retirement obligations previously associated with our offshore assets held by Denbury Offshore, Inc., which we sold in July 2004. At December 31, 2005 and 2004, $1.8 million and $2.6 million of our asset retirement obligation was classified in "Accounts payable and accrued liabilities" under current liabilities in our Consolidated Balance Sheets. We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $6.7 million at December 31, 2005, and $6.4 million at December 31, 2004, and are included in "Other assets" in our Consolidated Balance Sheets.

Note 5. Property and Equipment

	DECEMBER 31,	
(IN THOUSANDS)	2005	2004
OIL AND NATURAL GAS PROPERTIES:		
Proved properties	**$1,669,579**	$1,326,401
Unevaluated properties	**46,597**	20,253
Total	**1,716,176**	1,346,654
Accumulated depletion and depreciation	**(775,390)**	(686,799)
NET OIL AND NATURAL GAS PROPERTIES	**940,786**	659,855
CO_2 properties and equipment	**210,046**	132,685
Accumulated depletion and depreciation	**(15,544)**	(10,636)
NET CO_2 PROPERTIES	**194,502**	122,049
Capital leases	**6,997**	4,592
Accumulated depletion and depreciation	**(835)**	(50)
NET CAPITAL LEASES	**6,162**	4,542
Other	**27,650**	21,337
Accumulated depletion and depreciation	**(13,130)**	(10,421)
NET OTHER	**14,520**	10,916
NET PROPERTY AND EQUIPMENT	**$1,155,970**	$ 797,362

At December 31, 2005, we had $46.9 million of cost included in "CO_2 properties and equipment" related to the construction of a CO_2 pipeline. These costs were not being depreciated at December 31, 2005, as the pipeline was under construction. Depreciation will commence when the pipeline is placed into service, which is expected to be in the first quarter of 2006.

Unevaluated Oil and Natural Gas Properties Excluded From Depletion

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves can be assigned to such properties. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2005 and 2004, and the year in which they were incurred follows:

	DECEMBER 31, 2005				
	COSTS INCURRED DURING:				
(IN THOUSANDS)	2005	2004	2003	2002	TOTAL
Property acquisition costs	**$30,622**	**$2,368**	**$1,007**	**$ 527**	**$34,524**
Exploration costs	**6,493**	**2,245**	**1,107**	**2,228**	**12,073**
Total	**$37,115**	**$4,613**	**$2,114**	**$2,755**	**$46,597**

	DECEMBER 31, 2004				
	COSTS INCURRED DURING:				
(IN THOUSANDS)	2004	2003	2002	2001	TOTAL
Property acquisition costs	$ 3,400	$2,519	$1,207	$1,798	$ 8,924
Exploration costs	3,787	2,771	3,550	1,221	11,329
Total	$ 7,187	$5,290	$4,757	$3,019	$20,253

Property acquisition costs for 2005 are primarily associated with our acquisition of acreage in the Barnett Shale area and the acquisition of Lake St. John Field. Costs are transferred into the amortization base on an ongoing basis as the projects are evaluated and proved reserves established or impairment determined. We review the excluded properties for impairment at least annually. We currently estimate that evaluation of most of these properties and the inclusion of their costs in the amortization base is expected to be completed within five years. Until we are able to determine whether there are any proved reserves attributable to the above costs, we are not able to assess the future impact on the amortization rate.

Note 6. Notes Payable and Long-Term Indebtedness

	DECEMBER 31,	
(IN THOUSANDS)	2005	2004
7.5% Senior Subordinated Notes due 2015	**$150,000**	$ —
7.5% Senior Subordinated Notes due 2013	**225,000**	225,000
Discount on Senior Subordinated Notes due 2013	**(1,409)**	(1,603)
Capital lease obligations – Genesis	**6,444**	4,559
Senior bank loan	**—**	—
Total	**380,035**	227,956
Less current obligations	**574**	375
Long-term debt and capital lease obligations	**$379,461**	$227,581

7.5% Senior Subordinated Notes due 2015

On December 21, 2005, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 ("2015 Notes"). The 2015 Notes were priced at par and we used the $148.0 million of net proceeds from the offering to fund a portion of the $248 million oil and natural gas property acquisition, which closed in January 2006 (see Note 13). Pending the funding of this transaction in January 2006, the net proceeds were used to repay the borrowings under our bank credit facility with the balance temporarily invested in short-term investments and included as "Cash and cash equivalents" in our December 31, 2005 Consolidated Balance Sheet.

The 2015 Notes mature on December 15, 2015, and interest on the 2015 Notes is payable each June 15 and December 15. We may redeem the 2015 Notes at our option beginning December 15, 2010, at the following redemption prices: 103.75% after December 15, 2010, 102.5% after December 15, 2011, 101.25%, after December 15, 2012 and 100% after December 15, 2013. In addition, prior to December 15, 2008, we may at our option on one or more occasions redeem up to 35% of the 2015 Notes at a redemption price of 107.5% with the net cash proceeds from a stock offering. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2015 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

7.5% Senior Subordinated Notes due 2013

On March 25, 2003, we issued $225 million of 7.5% Senior Subordinated Notes due 2013 ("2013 Notes"). The 2013 Notes were priced at 99.135% of par and we used most of our $218.4 million of net proceeds from the offering, after underwriting and issuance costs, to retire our then existing $200 million of 9% Senior Subordinated Notes due 2008, including the Series B notes (see *Redemption of 9% Senior Subordinated Notes due 2008 (Including Series B Notes)* below).

The 2013 Notes mature on April 1, 2013, and interest on the 2013 Notes is payable each April 1 and October 1. We may redeem the 2013 Notes at our option beginning April 1, 2008, at the following redemption prices: 103.75% after April 1, 2008, 102.5% after April 1, 2009, 101.25% after April 1, 2010, and 100% after April 1, 2011 and thereafter. In addition, prior to April 1, 2006, we may redeem up to 35% of the 2013 Notes at a redemption price of 107.5% with net cash proceeds from a stock offering. The indenture under which the 2013 Notes were issued is essentially the same as the indenture covering our previously outstanding 9% notes. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2013 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

In connection with our internal reorganization to a holding-company-organizational structure (see Note 1), we entered into a First Supplemental Indenture dated December 29, 2003, which did not require the consent of the holders of the 2013 Notes. The supplemental indenture made Denbury Resources Inc. and Denbury Onshore, LLC, co-obligors of this debt. All of our significant subsidiaries continue to fully and unconditionally guarantee this debt. There were no other significant changes as part of the amendment.

Redemption of 9% Senior Subordinated Notes due 2008 (Including Series B Notes)

On April 16, 2003, we redeemed our $200 million of 9% Senior Subordinated Notes due 2008 at an aggregate cost of $209.0 million, including a $9.0 million call premium. As a result of this early redemption, we recorded a before-tax charge to earnings in the second quarter of 2003 of $17.6 million ($11.5 million after income tax), which included the $9.0 million call premium and the write-off of the remaining discount and debt issuance costs associated with these notes.

Senior Bank Loan

On September 1, 2004, we entered into a new bank credit agreement that modified the prior agreement by (i) creating a structure wherein the commitment amount and borrowing base amount are no longer the same, (ii) improving our credit pricing by reducing the interest rate chargeable at certain levels of borrowing, (iii) extending the term by three years to April 30, 2009, (iv) reducing the collateral requirements, (v) authorizing up to $20 million of possible future CO_2 volumetric production payment transactions with Genesis Energy, and (vi) other minor modifications and corrections. Under the new agreement, our borrowing base is currently set at $200 million, with an initial commitment amount of $100 million. The borrowing base represents the amount we can borrow from a credit standpoint based on our assets, as confirmed by the banks, while the commitment amount is the amount we asked the banks to commit to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request made by us in excess of the commitment amount, up to the borrowing base limit, although they are not obligated to fund any amount in excess of $100 million, the commitment amount. The advantage to us is that we will pay commitment fees on the commitment amount, not the borrowing base, thus lowering our overall cost of available credit. We had two minor amendments to our credit agreement in 2005, and in January 2006, we increased the commitment amount from $100 million to $150 million to allow additional availability under our credit line after closing the $248 million January 2006 acquisition (see Note 13).

The bank credit facility is secured by substantially all of our producing oil and natural gas properties and contains several restrictions including, among others: (i) a prohibition on the payment of dividends, (ii) a requirement for a minimum equity balance, (iii) a requirement to maintain positive working capital, as defined, (iv) a minimum interest coverage test and (v) a prohibition of most debt and corporate guarantees. We were in compliance with all of our bank covenants as of December 31, 2005. Our bank credit facility provides for a semiannual redetermination of the borrowing base on April 1 and October 1. Borrowings under the credit facility are generally in tranches that can have maturities up to one year. Interest on any borrowings are based on the Prime Rate or LIBOR rate plus an applicable margin as determined by the borrowings outstanding. The facility matures in April 2009.

As of December 31, 2005, we had no outstanding borrowings under the facility and $460,000 in letters of credit secured by the facility. The next scheduled redetermination of the borrowing base will be as of April 1, 2006, based on December 31, 2005 assets and proved reserves.

Indebtedness Repayment Schedule

At December 31, 2005, our indebtedness, excluding the discount on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

(IN THOUSANDS)	
2006	**$ 574**
2007	**631**
2008	**694**
2009	**764**
2010	**841**
Thereafter	**377,940**
Total indebtedness	**$381,444**

Note 7. Income Taxes

Our income tax provision (benefit) is as follows:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Current income tax expense (benefit):			
Federal	**$26,659**	$22,166	$ (91)
State	**518**	763	—
Total current income tax expense (benefit)	**27,177**	22,929	(91)
Deferred income tax expense:			
Federal	**44,191**	12,352	23,864
State	**10,202**	4,111	2,439
Total deferred income tax expense	**54,393**	16,463	26,303
Total income tax expense	**$81,570**	$39,392	$26,212

In conjunction with the sale of Denbury Offshore, Inc. in 2004, we utilized all of our federal tax net operating loss carryforwards and paid alternative minimum taxes of approximately $21 million. At December 31, 2005, we have approximately $24.6 million in state net operating loss carryforwards that begin to expire in 2013. As of December 31, 2005, we have an

Notes to Consolidated Financial Statements

estimated $42.1 million of enhanced oil recovery credits to carry forward related to our tertiary operations. These credits will begin to expire in 2020.

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2005 and 2004, balance sheet dates. We believe that we will be able to utilize all of our deferred tax assets at December 31, 2005, and therefore have provided no valuation allowance against our deferred tax assets. At December 31, 2005 and 2004, our deferred tax assets and liabilities were as follows:

	DECEMBER 31,	
(IN THOUSANDS)	2005	2004
Deferred tax assets:		
Loss carryforwards – state	**$ 983**	$ 5,290
Tax credit carryover	**14,103**	14,186
Enhanced oil recovery credit carryforwards	**42,127**	27,828
Derivative hedging contracts	**—**	2,920
Other	**1,196**	318
Total deferred tax assets	**58,409**	50,542
Deferred tax liabilities:		
Property and equipment	**(185,443)**	(120,038)
Asset retirement obligations	**(2,440)**	(2,440)
Total deferred tax liabilities	**(187,883)**	(122,478)
Total net deferred tax liability	**$(129,474)**	$ (71,936)

Our income tax provision varies from the amount that would result from applying the federal statutory income tax rate to income before income taxes as follows:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Income tax provision calculated using the federal statutory income tax rate	**$ 86,814**	$42,644	$28,054
State income taxes	**9,922**	4,874	2,398
Enhanced oil recovery credits	**(17,142)**	(7,986)	(4,687)
Other	**1,976**	(140)	447
Total income tax expense	**$ 81,570**	$39,392	$26,212

Note 8. Stockholders' Equity

Stock Split

On October 19, 2005, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, received one additional share of Denbury common stock for each share of common stock held at that time. Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock split, except for our December 31, 2004 balance sheet, which has not been retroactively adjusted to reflect the stock split.

Authorized

We are authorized to issue 250 million shares of common stock, par value $.001 per share, and 25 million shares of preferred stock, par value $.001 per share. The preferred shares may be issued in one or more series with rights and conditions determined by the Board of Directors.

Stock Repurchase Plan

Between August 2003 and June 30, 2005, Denbury had an active stock repurchase plan ("Plan") to purchase shares of our common stock on the NYSE in order for such repurchased shares to be reissued to our employees who participate in Denbury's Employee Stock Purchase Plan (see *Employee Stock Purchase Plan* below). The Plan provided for purchases through an independent broker of 100,000 shares of Denbury's common stock per fiscal quarter over a period of approximately 12 months, or a total of 400,000 shares per year. Purchases were made at prices and times determined at the discretion of the independent broker, provided however that no purchases were made during the last 10 business days of a fiscal quarter. During 2003, we purchased 200,000 shares at an average cost of $6.39 per share and reissued 183,676 of those shares under Denbury's Employee Stock Purchase Plan. In 2004, we repurchased into treasury 400,000 shares at an average cost of $9.95 per share and reissued 230,180 treasury shares under the Employee Stock Purchase Plan. In the first six months of 2005, we repurchased into treasury 200,000 shares under the Plan at an average cost of $15.82 per share and reissued 130,831 treasury shares under our ESPP. The repurchase program expired as of June 30, 2005, and the Board of Directors currently does not plan to renew the Plan until a significant portion of the treasury shares have been used under our ESPP.

Stock Incentive Plans

Denbury had two stock incentive plans in effect during 2005. The first plan has been in existence since 1995 (the "1995 Plan") and expired in August 2005. The 1995 Plan only provided for the issuance of stock options and in January 2005, we issued stock options under the 1995 Plan that utilized substantially all of the remaining shares. The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), has a 10-year term and was approved by the shareholders in May 2004. A total of 5.0 million shares of common stock is authorized for issuance pursuant to the 2004 Plan, of which no more than 2,750,000 shares may be issued in the form of restricted stock or performance vesting awards. At December 31, 2005, a total of 1,644,538 shares were available for future issuance, of which only 430,000 shares may be in the form of restricted stock or performance vesting awards. The 2004 Plan provides for the issuance of incentive and non-qualified stock options, restricted share awards and stock appreciation rights settled in stock that may be issued to officers, employees, directors and consultants.

Denbury has historically granted incentive and non-qualified stock options to all of its employees that generally become exercisable over a four-year vesting period with the specific terms of vesting determined by the Board of Directors at the time of grant. The options expire over terms not to exceed 10 years from the date of grant, 90 days after termination of employment or permanent disability or one year after the death of the optionee. The options are granted at the fair market value at the time of grant, which is generally defined in the 1995 Plan as the average closing price of our common stock for the 10 trading days prior to issuance, or in the case of the 2004 Plan, the closing price on the date of grant. These plans are administered by the Compensation Committee of Denbury's Board of Directors.

The following is a summary of our stock option activity over the last three years:

	YEAR ENDED DECEMBER 31,					
	2005		2004		2003	
	NUMBER OF OPTIONS	WEIGHTED AVERAGE PRICE	NUMBER OF OPTIONS	WEIGHTED AVERAGE PRICE	NUMBER OF OPTIONS	WEIGHTED AVERAGE PRICE
Outstanding at beginning of year	**8,880,314**	**$ 5.25**	10,652,432	$4.60	9,992,730	$4.23
Granted	**2,483,254**	**16.29**	2,019,620	7.18	1,915,216	5.67
Exercised	**(1,797,146)**	**5.37**	(2,528,568)	4.25	(1,100,180)	2.89
Forfeited	**(160,350)**	**8.86**	(1,263,170)	4.89	(155,334)	6.13
Outstanding at end of year	**9,406,072**	**8.07**	8,880,314	5.25	10,652,432	4.60
Exercisable at end of year	**2,509,635**	**$ 4.50**	3,088,824	$4.81	4,526,528	$5.06

The following is a summary of stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
	Number of Options Outstanding at 12/31/05	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options Exercisable at 12/31/05	Weighted Average Exercise Price
Range of Exercise Prices					
$1.88 – 2.25	**935,086**	**3.4 years**	**$ 2.07**	**935,086**	**$ 2.07**
$2.26 – 4.00	**1,299,688**	**6.0 years**	**3.56**	**75,440**	**3.75**
$4.01 – 5.75	**2,372,262**	**6.3 years**	**5.27**	**847,123**	**4.68**
$5.76 – 7.25	**1,973,989**	**6.7 years**	**6.80**	**385,993**	**6.69**
$7.26 – 11.25	**336,750**	**3.8 years**	**9.12**	**253,501**	**9.24**
$11.26 – 14.00	**1,592,623**	**9.0 years**	**13.76**	**9,102**	**12.65**
$14.01 – 25.25	**895,674**	**9.5 years**	**20.63**	**3,390**	**17.30**
	9,406,072	**6.7 years**	**8.07**	**2,509,635**	**4.50**

Restricted Stock

During August 2004 through January 2005, the Board of Directors, based on a recommendation by the Board's Compensation Committee, awarded the officers of Denbury a total of 2,200,000 shares of restricted stock and the independent directors of Denbury a total of 120,000 shares of restricted stock, all granted under Denbury's 2004 Omnibus Stock and Incentive Plan that was approved by Denbury's shareholders in May 2004. The holders of these shares have all of the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of the certificates until certain requirements are met. With respect to the 2,200,000 shares of restricted stock granted to officers of Denbury, the vesting restrictions on those shares are as follows: i) 65% of the awards vest 20% per year over five years and, ii) 35% of the awards vest upon retirement, as defined in the 2004 Plan. With respect to the 65% of the awards that vest over five years, on each annual vesting date, 66-2/3% of the vested shares may be delivered to the holder with the remaining 33-1/3% retained and held in escrow until the holder's separation from the Company. With respect to the 120,000 restricted shares issued to Denbury's independent board members, the shares vest 20% per year over five years. For these shares, on each annual vesting date, 40% of such vested shares may be delivered to the holder with the remaining 60% retained and held in escrow until the holder's separation from the Company. All restricted shares vest upon death, disability or a change in control.

Upon issuance of the 2,320,000 shares of restricted stock pursuant to the 2004 Omnibus Stock and Incentive Plan, we recorded deferred compensation expense of $23.6 million, the market value of the shares on the grant dates, as a reduction to shareholders' equity. This expense will be amortized over the applicable five-year or retirement date vesting periods. The compensation expense recorded with respect to the restricted shares for the years ending December 31, 2005 and 2004, was $4.1 million and $1.6 million, respectively.

Employee Stock Purchase Plan

We have a Stock Purchase Plan that is authorized to issue up to 3,500,000 shares of common stock to all full-time employees. As of December 31, 2005, there are 452,371 authorized shares remaining to be issued under the plan. In accordance with the plan, employees may contribute up to 10% of their base salary and Denbury matches 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock or treasury stock purchased by the Company in the open market for that purpose, in either case, based on the market value of Denbury's common stock at the end of each quarter. We recognize compensation expense for the 75% company match portion, which totaled $1.2 million, $1.0 million, and $1.0 million for the years ended December 31, 2005, 2004 and 2003, respectively. This plan is administered by the Compensation Committee of Denbury's Board of Directors.

401(k) Plan

Denbury offers a 401(k) Plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. Up to 3% of an employee's compensation, as defined by the plan, is matched by Denbury at 100% and an employee's contribution between 3% and 6% of compensation is matched by Denbury at 50%. Denbury's match is vested immediately. During 2005, 2004 and 2003, Denbury's matching contributions were approximately $1.2 million, $1.0 million, and $1.1 million, respectively, to the 401(k) Plan.

Note 9. Derivative Contracts

Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts and accordingly de-designated our derivative instruments from hedge accounting treatment. As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change. Additionally, the balance remaining in "Accumulated comprehensive loss" at December 31, 2004, related to the derivative contracts was amortized over the remaining life of the contracts, all of which expired in 2005.

We enter into various financial contracts to economically hedge our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have historically consisted of price floors, collars and fixed price swaps. Historically, we have generally attempted to hedge between 50% and 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover a majority of our budgeted exploration and development expenditures without incurring significant debt, although our hedging percentage may vary relative to our debt levels. For 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification.

The following is a summary of the net loss on our commodity contracts that qualified for hedge accounting treatment, covering those periods prior to our discontinuance of hedge accounting effective January 1, 2005, and is included in "Loss on effective hedge contracts" in our Consolidated Statements of Operations:

	YEAR ENDED DECEMBER 31,	
(IN THOUSANDS)	2004	2003
Settlements of hedge contracts – Oil	$(50,072)	$(20,337)
Settlements of hedge contracts – Gas	(20,397)	(41,873)
Loss on effective hedge contracts	$(70,469)	$(62,210)

The following is a summary of "Commodity derivative expense," included in our Consolidated Statements of Operations:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Settlements of derivative contracts not designated as hedges – oil	**$ —**	$14,088	$ —
Settlements of derivative contracts not designated as hedges – gas	**16,761**	—	—
Hedge ineffectiveness on contracts qualifying for hedge accounting	**—**	2,687	282
Reclassification of accumulated other comprehensive income balance	**7,684**	(955)	—
Adjustments to fair value associated with contracts not designated as hedges	**4,517**	2,086	—
Adjustment to fair value associated with contracts transferred in sale of offshore properties	**—**	(2,548)	—
Amortization of contract premiums	**—**	—	1,192
Amortization of terminated Enron-related hedges over the original contract periods	**—**	—	(5,052)
Commodity derivative expense (income)	**$28,962**	$15,358	$(3,578)

Notes to Consolidated Financial Statements

Derivative Oil Contracts at December 31, 2005

TYPE OF CONTRACT AND PERIOD	NYMEX CONTRACT PRICES PER Bbl Bbls/d	NYMEX CONTRACT PRICES PER Bbl SWAP PRICE	ESTIMATED FAIR VALUE AT DECEMBER 31, 2005 (IN THOUSANDS)
Swap Contracts			
Jan. 2006 – Dec. 2006	**2,200**	**$59.65**	**$(2,759)**
Jan. 2007 – Dec. 2007	**2,000**	**58.93**	**(3,353)**
Jan. 2008 – Dec. 2008	**2,000**	**57.34**	**(3,271)**

At December 31, 2005, our derivative contracts were recorded at their fair value, which was a liability of $9.4 million. All of the hedging contracts as of December 31, 2005, were put in place to hedge the estimated proved production from the $248 million acquisition which closed in January 2006 (see Note 13, "Subsequent Events").

Note 10. Commitments and Contingencies

We have operating leases for the rental of equipment, office space, and vehicles that totaled $37.2 million, $21.6 million, and $16.6 million as of December 31, 2005, 2004, and 2003, respectively. During the last three years, we entered into lease financing agreements for equipment at certain of our oil and natural gas properties and CO_2 source fields. These lease financings totaled $17.3 million during 2005, $6.9 million during 2004 and $6.1 million during 2003 with associated required monthly payments of $223,000 for the 2005 leases, $91,000 for the 2004 leases and $81,000 for the 2003 leases. All of these leases have seven-year terms.

In 2004 and 2005, we entered into three agreements with Genesis to transport crude oil and CO_2. These agreements are accounted for as capital leases and are discussed in detail in Note 3.

At December 31, 2005, long-term commitments for these items require the following future minimum rental payments:

(IN THOUSANDS)	CAPITAL LEASES	OPERATING LEASES
2006	**$ 1,185**	**$ 6,971**
2007	**1,185**	**6,959**
2008	**1,185**	**6,812**
2009	**1,185**	**5,931**
2010	**1,185**	**4,392**
Thereafter	**3,486**	**6,171**
Total minimum lease payments	**9,411**	**$37,236**
Less: Amount representing interest	**(2,967)**	
Present value of minimum lease payments	**$ 6,444**	

Long-term contracts require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis related to three CO_2 volumetric production payments (see Note 3). Based upon the maximum amounts deliverable as stated in the contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 390 Bcf of CO_2 to these customers over the next 18 years, with a maximum volume required in any given year of approximately 113 MMcf/d. However, since the group as a whole has historically purchased less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that the amount of CO_2 that we will ultimately be required to deliver will be significantly less than the contractual commitment. Given the size of our proven CO_2 reserves at December 31, 2005 (approximately 4.6 Tcf before deducting approximately 237.1 Bcf for the VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we can meet these delivery obligations.

Denbury is subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes that it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses, including those noted below. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that we may have a range of legal exposure that would require accrual. The estimate of the potential impact from the following legal proceedings on our financial position or overall results of operations could change in the future.

Along with two other companies, we have been named in a lawsuit styled *J. Paulin Duhe, Inc. vs. Texaco, Inc., et al*, Cause No. 101,227, filed in late 2003 in the 16th Judicial District Court, Division "E," Terrebonne Parish, Louisiana, seeking restoration to its original condition of property on which oil has been produced over the past 70 years. The contract and tort claims by the plaintiffs allege surface and groundwater damage of 26 acres that are part of our Iberia Field in Iberia Parish, Louisiana. Recently, plaintiff's experts have initially alleged that clean-up of alleged contamination of the property would cost $79.0 million, although settlement offers by plaintiffs have already been made for much smaller sums. The property was originally leased to Texaco, Inc. for mineral development in 1934 and Denbury acquired its interest in the property in August 2000 from Manti Operating Company. During 2005, the courts ruled that the plaintiffs' claims were premature in insofar as they sought to enforce the end of lease restoration obligation. Other claims were not dismissed and certain aspects of the litigation are ongoing. We believe that we are indemnified by the prior owner, which we expect to cover our exposure to most damages, if any, found to have occurred prior to the time that we purchased the property. We believe that the allegations of this lawsuit are subject to a number of defenses, are without merit and we and the other defendants plan to vigorously defend this lawsuit, and if necessary, we will seek indemnification from the prior owner.

On December 29, 2003, an action styled *Harry Bourg Corporation vs. Exxon Mobil Corporation, et al,* Cause No. 140749, was filed in the 32nd Judicial District Court, Terrebonne Parish, Louisiana against Denbury and 11 other oil companies and their predecessors alleging damage as the result of mineral exploration activities conducted by these oil and gas operators/ companies over the last 60 years. Plaintiff has asked for restoration of the 10,000-acre property and/or damages in claims made under tort law and various oil and gas contracts. The Bourg Corporation produced preliminary expert reports that allege damages of approximately $100.0 million against the defendants as a group. Discovery is continuing in this case, with trial currently set for June 2006. Depending on the outcome of the case, we may have indemnification obligations to prior owners. We believe we have historical documents and matters of fact which we believe provide strong defenses against these claims and we plan to vigorously defend this lawsuit along with the other defendants.

Note 11. Supplemental Information

Significant Oil and Natural Gas Purchasers

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. The loss of any purchaser would not be expected to have a material adverse effect upon our operations. For the year ended December 31, 2005, three purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%), Hunt Crude Oil Supply Co. (20%) and Sunoco, Inc. (13%). For the year ended December 31, 2004, we had two significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Hunt Crude Oil Supply Co. (21%) and Genesis (14%). For the year ended December 31, 2003, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Crude Oil Supply Co. (15%) and Genesis (12%).

Accounts Payable and Accrued Liabilities

	DECEMBER 31,	
(IN THOUSANDS)	2005	2004
Accounts payable	**$ 53,306**	$26,262
Accrued exploration and development costs	**23,635**	5,439
Accrued lease operating expense	**5,435**	2,194
Accrued compensation	**5,287**	5,613
Accrued interest	**4,582**	4,219
Asset retirement obligations – current	**1,791**	2,596
Other	**10,804**	3,106
Total	**$104,840**	$49,429

Supplemental Cash Flow Information

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Interest paid, net of amounts capitalized	**$16,622**	$18,099	$23,525
Income taxes paid	**21,000**	20,726	184

During 2005, we capitalized $1.6 million of interest relating to the construction of our CO_2 pipeline to East Mississippi. We recorded a non-cash increase to property and debt in the amount of $2.4 million in 2005 and $4.6 million in 2004, related to capital leases. In August through December 2004, we issued 2,300,000 shares of restricted stock with a market value of $23.3 million on the date of grant. In January 2005, we issued 20,000 shares of restricted stock with a market value of $0.3 million on the date of grant. See Note 8, "Stockholders' Equity-Restricted Stock."

Fair Value of Financial Instruments

	DECEMBER 31,			
	2005		2004	
(IN THOUSANDS)	CARRYING AMOUNT	ESTIMATED FAIR VALUE	CARRYING AMOUNT	ESTIMATED FAIR VALUE
7.5% Senior Subordinated Notes due 2013	**$223,591**	**$228,375**	$223,397	$243,000
7.5% Senior Subordinated Notes due 2015	**150,000**	**152,250**	—	—

The fair values of our senior subordinated notes are based on quoted market prices. The fair values of our short-term investments are discussed in Note 1. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 12. Condensed Consolidating Financial Information

On December 29, 2003, we amended the indenture for our 7.5% Senior Subordinated Notes due 2013 to reflect our new holding company organizational structure (see Note 1 and Note 6). As part of this restructuring our indenture was amended so that both Denbury Resources Inc. and Denbury Onshore, LLC became co-obligors of our subordinated debt. Prior to this restructure, Denbury Resources Inc. was the sole obligor. Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc.'s subsidiaries other than minor subsidiaries. The results of our equity interest in Genesis is reflected through the equity method by one of our subsidiaries, Denbury Gathering & Marketing. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and significant subsidiaries:

Condensed Consolidating Balance Sheets

(IN THOUSANDS)	DECEMBER 31, 2005				
	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
ASSETS					
Current assets	**$222,858**	**$ 297,575**	**$ 2,577**	**$ (223,827)**	**$ 299,183**
Property and equipment	**—**	**1,155,923**	**47**	**—**	**1,155,970**
Investment in subsidiaries (equity method)	**506,862**	**—**	**505,540**	**(1,001,573)**	**10,829**
Other assets	**154,288**	**37,120**	**169**	**(152,490)**	**39,087**
Total assets	**$884,008**	**$1,490,618**	**$508,333**	**$(1,377,890)**	**$1,505,069**
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	**$ 346**	**$ 376,194**	**$ 1,351**	**$ (223,827)**	**$ 154,064**
Long-term liabilities	**150,000**	**619,713**	**120**	**(152,490)**	**617,343**
Stockholders' equity	**733,662**	**494,711**	**506,862**	**(1,001,573)**	**733,662**
Total liabilities and stockholders' equity	**$884,008**	**$1,490,618**	**$508,333**	**$(1,377,890)**	**$1,505,069**

(IN THOUSANDS)	DECEMBER 31, 2004				
	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
ASSETS					
Current assets	$ 1	$171,997	$204,709	$ (203,861)	$172,846
Property and equipment	—	796,578	784	—	797,362
Investment in subsidiaries (equity method)	541,671	—	333,907	(868,787)	6,791
Other assets	—	15,707	2,271	(2,271)	15,707
Total assets	$541,672	$984,282	$541,671	$(1,074,919)	$992,706
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ —	$286,767	$ —	$ (203,861)	$ 82,906
Long-term liabilities	—	370,399	—	(2,271)	368,128
Stockholders' equity	541,672	327,116	541,671	(868,787)	541,672
Total liabilities and stockholders' equity	$541,672	$984,282	$541,671	$(1,074,919)	$992,706

Condensed Consolidating Statements of Operations

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2005				
	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Revenues	**$ 313**	**$560,079**	**$ —**	**$ —**	**$560,392**
Expenses	**485**	**310,974**	**1,206**	**—**	**312,665**
Income before the following:	**(172)**	**249,105**	**(1,206)**	**—**	**247,727**
Equity in net earnings of subsidiaries	**166,576**	**—**	**167,378**	**(333,640)**	**314**
Income before income taxes	**166,404**	**249,105**	**166,172**	**(333,640)**	**248,041**
Income tax provision	**(67)**	**82,041**	**(404)**	**—**	**81,570**
Net income	**$166,471**	**$167,064**	**$166,576**	**$(333,640)**	**$166,471**

Notes to Consolidated Financial Statements

Condensed Consolidating Statements of Operations (continued)

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2004 DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Revenues	$ —	$320,328	$62,644	$ —	$382,972
Expenses	171	222,988	37,837	—	260,996
Income before the following:	(171)	97,340	24,807	—	121,976
Equity in net earnings of subsidiaries	82,554	—	67,122	(149,812)	(136)
Income before income taxes	82,383	97,340	91,929	(149,812)	121,840
Income tax provision	(65)	30,082	9,375	—	39,392
Net income	$82,448	$ 67,258	$82,554	$ (149,812)	$ 82,448

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2003 DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Revenues	$ —	$238,072	$94,942	$ —	$333,014
Expenses	—	196,392	56,725	—	253,117
Income before the following:	—	41,680	38,217	—	79,897
Equity in net earnings of subsidiaries	56,553	—	40,667	(96,964)	256
Income before income taxes and cumulative effect of change in accounting principle	56,553	41,680	78,884	(96,964)	80,153
Income tax provision	—	5,250	20,962	—	26,212
Income before cumulative effect of change in accounting principle	56,553	36,430	57,922	(96,964)	53,941
Cumulative effect of a change in accounting principle, net of income tax	—	3,981	(1,369)	—	2,612
Net income	$56,553	$ 40,411	$56,553	$(96,964)	$ 56,553

Condensed Consolidating Statements of Cash Flows

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2005 DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Cash flow from operations	**$ (5,298)**	**$ 365,714**	**$544**	**$ —**	**$ 360,960**
Cash flow from investing activities	**(150,000)**	**(383,666)**	**(21)**	**150,000**	**(383,687)**
Cash flow from financing activities	**155,298**	**149,479**	**—**	**(150,000)**	**154,777**
Net increase in cash flow	**—**	**131,527**	**523**	**—**	**132,050**
Cash, beginning of period	**1**	**32,881**	**157**	**—**	**33,039**
Cash, end of period	**$ 1**	**$ 164,408**	**$680**	**$ —**	**$ 165,089**

Condensed Consolidating Statements of Cash Flows (continued)

	YEAR ENDED DECEMBER 31, 2004				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Cash flow from operations	$(9,192)	$ 331,123	$(153,279)	$ —	$ 168,652
Cash flow from investing activities	—	(246,973)	153,423	—	(93,550)
Cash flow from financing activities	9,192	(75,443)	—	—	(66,251)
Net increase in cash flow	—	8,707	144	—	8,851
Cash, beginning of period	1	24,174	13	—	24,188
Cash, end of period	$ 1	$ 32,881	$ 157	$ —	$ 33,039

	YEAR ENDED DECEMBER 31, 2003				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Cash flow from operations	$ —	$146,639	$ 50,976	$ —	$ 197,615
Cash flow from investing activities	—	(81,256)	(54,622)	—	(135,878)
Cash flow from financing activities	1	(61,490)	—	—	(61,489)
Net increase (decrease) in cash flow	1	3,893	(3,646)	—	248
Cash, beginning of period	—	20,281	3,659	—	23,940
Cash, end of period	$ —	$ 24,174	$ 13	$ —	$ 24,188

Note 13. Subsequent Events

On January 31, 2006, we completed an acquisition of three producing oil properties that are future potential CO_2 tertiary oil flood candidates: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. We expect to begin our initial tertiary development work at Tinsley Field during 2006 with more significant work during 2007. The timing of tertiary development at Citronelle Field is uncertain as we will need to build a 60- to 70-mile pipeline extension of our line to East Mississippi before flooding can commence, and South Cypress Creek will probably be flooded following our initial development of our other East Mississippi properties.

The adjusted purchase price is approximately $248 million, after adjusting for interim net cash flow and minor purchase price adjustments. The acquisition was funded with the proceeds of $150 million of senior subordinated notes issued in December 2005 and bank financing under the Company's existing credit facility.

On January 11, 2006, we increased the commitment on our bank credit line from $100 million to $150 million to allow additional availability under our credit line after closing the $248 million January 2006 acquisition discussed above.

Note 14. Supplemental Oil and Natural Gas Disclosures (unaudited)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease, or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas.

Notes to Consolidated Financial Statements

Costs incurred in oil and natural gas activities were as follows:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2005	2004	2003
Property acquisitions:			
Proved	**$ 63,509**	$ 22,271	$ 22,307
Unevaluated	**32,874**	3,459	3,955
Exploration	**45,652**	23,987	34,050
Development	**237,201**	128,351	98,132
Asset retirement obligations	**4,559**	3,174	3,405
Total costs incurred(1)	**$383,795**	$181,242	$161,849

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $5.1 million, $5.1 million, $5.5 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities, excluding corporate overhead and interest costs, were as follows:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS, EXCEPT PER BOE DATA)	2005	2004	2003
Oil, natural gas and related product sales	**$549,055**	$444,777	$385,463
Loss on effective hedge contracts	**—**	(70,469)	(62,210)
Total revenues	**549,055**	374,308	323,253
Lease operating costs	**108,550**	87,107	89,439
Production taxes and marketing expenses	**27,582**	18,737	14,819
Depletion, depreciation and accretion	**90,631**	90,913	90,694
Commodity derivative expense	**28,962**	15,358	(3,578)
Net operating income	**293,330**	162,193	131,879
Income tax provision	**96,464**	52,437	45,427
Results of operations from oil and natural gas producing activities	**$196,866**	$109,756	$ 86,452
Depletion, depreciation and accretion per BOE	**$ 8.33**	$ 7.54	$ 7.16

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. The reserves were prepared in accordance with guidelines established by the Securities and Exchange Commission and, accordingly, were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the reserve report date were used without any escalation. (See Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves below for a discussion of the effect of the different prices on reserve quantities and values.) Operating costs, production and ad valorem taxes and future development costs were based on current costs with no escalation.

We have a corporate policy whereby we do not book proved undeveloped reserves until we have committed to perform the required development operations, the majority of which we generally expect to commence within one to two years. We also have a corporate policy whereby proved undeveloped reserves must be economic at prices significantly lower than the year-end prices used in our reserve report; i.e., at prices closer to historical averages.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of our reserves are located in the United States.

Estimated Quantities of Reserves

	YEAR ENDED DECEMBER 31,					
	2005		2004		2003	
	OIL (MBbl)	GAS (MMcf)	OIL (MBbl)	GAS (MMcf)	OIL (MBbl)	GAS (MMcf)
Balance at beginning of year	**101,287**	**168,484**	91,266	221,887	97,203	200,947
Revisions of previous estimates	**(3,613)**	**(12,047)**	(3,271)	2,898	2,958	(25,451)
Revisions due to price changes	**872**	**1,268**	492	25	50	(152)
Extensions and discoveries	**1,214**	**117,512**	1,575	61,158	1,059	68,408
Improved recovery(1)	**13,276**	**—**	18,863	—	4,009	—
Production	**(7,305)**	**(21,424)**	(7,044)	(30,094)	(6,896)	(34,623)
Acquisition of minerals in place	**442**	**24,574**	429	5,304	838	14,541
Sales of minerals in place	**—**	**—**	(1,023)	(92,694)	(7,955)	(1,783)
Balance at end of year	**106,173**	**278,367**	101,287	168,484	91,266	221,887
Proved Developed Reserves:						
Balance at beginning of year	**55,998**	**94,573**	53,804	144,750	62,398	142,812
Balance at end of year	**59,640**	**151,681**	55,998	94,573	53,804	144,750

(1) Improved recovery additions result from the application of secondary recovery methods such as water-flooding or tertiary recovery methods such as CO_2 flooding.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves (Standardized Measure) does not purport to present the fair market value of our oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying year-end prices to the estimated future production of year-end proved reserves. The product prices used in calculating these reserves have varied widely during the three-year period. These prices have a significant impact on both the quantities and value of the proven reserves as the reduced oil price causes wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas year-end prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

	DECEMBER 31,		
	2005	2004	2003
Oil (NYMEX)	**$61.04**	$43.45	$32.52
Natural Gas (Henry Hub)	**10.08**	6.18	5.97

Future cash inflows were reduced by estimated future production, development and abandonment costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net

Notes to Consolidated Financial Statements

operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

(IN THOUSANDS)	DECEMBER 31, 2005	2004	2003
Future cash inflows	**$ 8,197,957**	$ 4,742,276	$ 4,059,424
Future production costs	**(2,069,015)**	(1,509,280)	(1,120,741)
Future development costs	**(525,877)**	(340,879)	(300,981)
Future net cash flows before taxes	**5,603,065**	2,892,117	2,637,702
Future income taxes	**(1,944,430)**	(906,221)	(748,273)
Future net cash flows	**3,658,635**	1,985,896	1,889,429
10% annual discount for estimated timing of cash flows	**(1,574,186)**	(856,700)	(765,302)
Standardized measure of discounted future net cash flows	**$ 2,084,449**	$ 1,129,196	$ 1,124,127

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2005	2004	2003
Beginning of year	**$1,129,196**	$1,124,127	$1,028,976
Sales of oil and natural gas produced, net of production costs	**(412,923)**	(339,250)	(281,205)
Net changes in sales prices	**1,261,231**	352,830	141,932
Extensions and discoveries, less applicable future development and production costs	**461,936**	151,014	235,228
Improved recovery[(1)]	**204,116**	190,033	40,663
Previously estimated development costs incurred	**110,424**	55,091	52,874
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	**(261,730)**	(197,959)	(157,989)
Accretion of discount	**164,329**	156,637	142,622
Acquisition of minerals in place	**44,807**	9,003	44,856
Sales of minerals in place	**—**	(300,481)	(78,830)
Net change in income taxes	**(616,937)**	(71,849)	(45,000)
End of year	**$2,084,449**	$1,129,196	$1,124,127

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding.

CO_2 Reserves

Based on engineering reports prepared by DeGolyer and MacNaughton, our CO_2 reserves, on a 100% working interest basis, were estimated at approximately 4.6 Tcf at December 31, 2005 (includes 237.1 Bcf of reserves dedicated to three volumetric production payments with Genesis), 2.7 Tcf at December 31, 2004 (includes 178.7 Bcf of reserves dedicated to two volumetric production payments), and 1.6 Tcf at December 31, 2003 (includes 162.6 Bcf of reserves dedicated to a volumetric production payment). We make reference to the gross amount of proved reserves as that is the amount that is available both for Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream for both of these purposes.

Note 15. Unaudited Quarterly Information

IN THOUSANDS, EXCEPT PER SHARE AMOUNTS	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
2005				
Revenues	**$113,362**	**$ 127,983**	**$141,858**	**$ 177,189**
Expenses	**69,754**	**67,491**	**83,249**	**92,171**
Net income	**30,067**	**40,672**	**38,546**	**57,185**
Net income per share:				
Basic	**0.27**	**0.37**	**0.34**	**0.51**
Diluted	**0.26**	**0.34**	**0.32**	**0.48**
Cash flow from operations	**66,629**	**88,385**	**76,287**	**129,659**
Cash flow used for investing activities[1]	**(59,614)**	**(117,530)**	**(75,840)**	**(130,703)**
Cash flow provided by financing activities[2]	**2,688**	**11,719**	**11,227**	**129,143**
2004				
Revenues	$ 97,748	$ 106,213	$ 88,029	$ 90,982
Expenses	64,710	77,277	61,886	57,123
Net income[5]	22,304	19,389	18,274	22,481
Net income per share:				
Basic	0.21	0.18	0.17	0.20
Diluted	0.20	0.17	0.16	0.19
Cash flow from operations	52,995	53,210	44,766	17,681
Cash flow provided by (used for) investing activities[3]	(68,111)	(51,351)	69,046	(43,134)
Cash flow provided by (used for) financing activities[4]	8,136	8,873	(84,035)	775

(1) *In November 2005, we made a $25 million deposit of earnest money associated with a pending acquisition of oil properties (see Notes 2 and 13).*

(2) *In December 2005, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 (see Note 6).*

(3) *In July 2004, we sold Denbury Offshore, Inc. a subsidiary that held our offshore assets. We used $85 million of the proceeds to retire debt (see Note 2).*

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

On May 12, 2004, the Audit Committee of Denbury approved the appointment of PricewaterhouseCoopers LLP as the Company's independent registered public accounting firm for the fiscal year ending December 31, 2004, replacing Deloitte & Touche LLP, which had been the Company's independent auditors since 1990. This decision was affirmed by Denbury's Board of Directors. Information regarding this change in independent auditors was included in our report on Form 8-K dated May 17, 2004, and subsequently amended on May 24, 2004. There have been no other changes in accountants nor any disagreements with accountants.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K and have determined that such disclosure controls and procedures are effective as of December 31, 2005, in ensuring that material information required to be disclosed in this annual report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

In January 2005, we began processing our transactions on a newly implemented accounting software system. We changed systems in order (i) to integrate and automate more of our functions, which will also allow us to have more information in one integrated database, (ii) to provide operating efficiencies, (iii) to enable us to close our books in a more timely manner without sacrificing quality, (iv) to review and improve our processes and (v) improve the internal control surrounding our computer systems. As a result of moving to a new system in January 2005, several control procedures were required to be changed, documented, and evaluated in order to conform to our new system. While we believe that our new accounting system will ultimately strengthen our internal control system, there are inherent weaknesses in implementing any new system. We have tested these control changes and have not found any reason to believe that our internal controls over financial reporting are not effective in all material respects. We are continuing to implement additional features and aspects of our new accounting system and will continue to evaluate the impact and effect of a new accounting system on our internal controls and procedures and it is possible that we may find weaknesses in the future.

During 2005, information was reported on our whistleblower hotline regarding misconduct by oilfield vendors and certain employees, including alleged improper billings and payments by certain vendors to, or on behalf of employees, misuse of Company property and operational information, and the failure by employees to report transactions entered into with the Company. At the direction of the Audit Committee of our Board of Directors, and in conjunction with outside counsel retained by the Audit Committee, investigations have been undertaken to (1) gain an understanding of both the facts and circumstances surrounding these matters, (2) review our management practices and internal controls as they relate to these areas, (3) ascertain whether, in fact, there were violations of the Company's Code of Business Conduct and Ethics, (4) make recommendations as to necessary improvements in such practices and controls, and (5) recommend other corrective actions, as deemed appropriate. As a result of our investigations to date, we have dismissed three employees, taken disciplinary action against another employee, and terminated all future business with certain vendors. The estimated amount of improper vendor billings and payments discovered to date is inconsequential to our previously issued financial statements and to the financial statements contained in this report on Form 10-K. We expect to recover a portion of the improper vendor billings from our vendors. We further believe that the ultimate resolution of these matters will not materially adversely affect our financial condition, results of operations or business. We believe that our whistleblower hotline was effective in alerting us to improper vendor and employee conduct and allowing us to remedy the matter.

Controls and policies in place to prevent these occurrences were overridden by employee misconduct in the vendor approval and payment process and in adherence to the Company's Code of Business Conduct and Ethics. As a result of our investigation, we are in the process of implementing certain improvements to strengthen our management practices and policies and internal controls, as set forth below:

1. Heighten authorization and documentation requirements for purchasing, including implementation of a centralized purchasing function;
2. Contact our vendors to inform them of the changes in our procurement practices and pursue their cooperation and assistance in complying with and assisting us in enforcing our new policies;
3. Increase our internal audit reviews in the area of purchasing, bidding, and invoice approval; and
4. Review, refine, emphasize and enforce our Code of Business Conduct and Ethics and purchasing policies and procedures with employees and vendors.

ITEM 9B. OTHER INFORMATION

None.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

Directors of the Company

Information as to the names, ages, positions and offices with Denbury, terms of office, periods of service, business experience during the past five years and certain other directorships held by each director or person nominated to become a director of Denbury will be set forth in the Election of Directors segment of the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 10, 2006, (Annual Meeting) and is incorporated herein by reference.

Executive Officers of the Company

Information concerning the executive officers of Denbury will be set forth in the "Management" section of the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 and the rules thereunder require the Company's executive officers and directors, and persons who beneficially own more than ten percent (10%) of a registered class of the Company's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission and exchanges and to furnish the Company with copies. Based solely on its review of the copies of such forms received by it, or written representations from such persons, the Company is not aware of any person who failed to timely file any reports required by Section 16(a) to be filed for fiscal 2005.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers and Principal Executive Officer. This Code of Ethics, including any amendments or waivers, is posted on our website at **www.denbury.com**.

ITEM 11. EXECUTIVE COMPENSATION

Information concerning remuneration received by Denbury's executive officers and directors will be presented under the caption "Statement of Executive Compensation" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information as to Denbury's common stock that may be issued under our equity compensation plans, which plans have been approved by shareholders, and the number of shares of Denbury's common stock beneficially owned as of March 1, 2006, by each of its directors and nominees for director, its five most highly compensated executive officers and its directors and executive officers as a group will be presented under the captions "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information on related transactions will be presented under the caption "Compensation Committee Interlocks and Insider Participation and Interests of Insiders in Material Transactions" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required to be presented on principal accountant fees and services will be presented under the caption "Relationship with Independent Accountants" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on page 50. 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 consolidated financial statements.

Exhibits. The following exhibits are filed as part of this report.

EXHIBIT NO.	EXHIBIT
2(a)	Agreement and Plan of Merger to Form Holding Company, dated as of December 22, 2003, but effective December 29, 2003, at 9:00 a.m. EST, by and among the Registrant, the Predecessor and Denbury Onshore, LLC (incorporated by reference as Exhibit 2.1 of our Form 8-K filed December 29, 2003).
2(b)	Stock Purchase Agreement made as of July 19, 2004, between Denbury Resources Inc. and Newfield Exploration Company (incorporated by reference as Exhibit 2.14 of our Form 8-K filed August 4, 2004).
3(a)	Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on December 29, 2003 (incorporated by reference as Exhibit 3.1 of our Form 8-K filed December 29, 2003).
3(b)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 20, 2005 (incorporated by reference as Exhibit 3(a) of our Form 10-Q filed November 8, 2005).
3(c)	Bylaws of Denbury Resources Inc., a Delaware corporation, adopted December 29, 2003 (incorporated by reference as Exhibit 3.2 of our Form 8-K filed December 29, 2003).
4(a)	Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015 among Denbury Resources Inc., certain of its subsidiaries, and JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 9, 2005).
4(b)	Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 among Denbury Resources Inc., certain of its subsidiaries and JP Morgan Chase Bank as trustee, dated March 25, 2003 (incorporated by reference as Exhibit 4(a) to our Registration Statement No. 333-105233-04 on Form S-4, filed May 14, 2003).
4(c)	First Supplemental Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of December 29, 2003, among Denbury Resources Inc., certain of its subsidiaries, and the JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 29, 2003).
10(a)	Purchase and Sale Agreement dated as of November 9, 2005, by and among Merit Management Partners I, L. P., Merit Energy Partners III, L.P. and Merit Energy Partners D-III, L.P., and Denbury Onshore, LLC. (incorporated by reference as Exhibit 10.1 of our Form 8-K filed February 3, 2006).
10(b)	Fifth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, Bank One, N.A. as Administrative Agent, and certain other financial institutions, dated September 1, 2004 (incorporated by reference as Exhibit 1.1 of our Form 8-K filed September 3, 2004).
10(c)	First Amendment to Fifth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc, as Parent Guarantor, Bank One, N.A. as Administrative Agent, and certain other financial institutions dated as of April 1, 2005 (incorporated by reference as Exhibit 10 of our Form 10-Q filed May 9, 2005).

EXHIBIT NO.	EXHIBIT
10(d) *	Second Amendment to Fifth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc, as Parent Guarantor, Bank One, N.A. as Administrative Agent, and certain other financial institutions dated as of December 1, 2005.
10(e) *	Amendment for Increased Commitment from $100 million to $150 million to Fifth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc, as Parent Guarantor, Bank One, N.A. as Administrative Agent, and certain other financial institutions dated as of January 11, 2006.
10(f) **	Denbury Resources Inc. Amended and Restated Stock Option Plan (incorporated by reference as Exhibit 99 of our Registration Statement No. 333-106253 on Form S-8, filed June 18, 2003).
10(g) **	Denbury Resources Inc. Stock Purchase Plan, as amended (incorporated by reference as Exhibit 4(g) of our Registration Statement on Form S-8, No. 333-1006, filed February 2, 1996, with amendments incorporated by reference as exhibits of our Registration Statements on Forms S-8, No. 333-70485, filed January 12, 1999, No. 333-39218, filed June 13, 2000 and No. 333-90398, filed June 13, 2002).
10(h) **	Form of indemnification agreement between Denbury Resources Inc. and its officers and directors (incorporated by reference as Exhibit 10 of our Form 10-Q for the quarter ended June 30, 1999).
10(i) **	Denbury Resources Inc. Directors Compensation Plan (incorporated by reference as Exhibit 4 of our Registration Statement on Form S-8, No. 333-39172, filed June 13, 2000, amended March 2, 2001 and May 11, 2005).
10(j) **	Denbury Resources Severance Protection Plan, dated December 6, 2000 (incorporated by reference as Exhibit 10(f) of our Form 10-K for the year ended December 31, 2000).
10(k) **	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan as amended (incorporated by reference as Exhibit 10(g) of our Form 10-K for the year ended December 31, 2004).
10(l) * **	Description of cash bonus compensation arrangements for employees and officers.
10(m) * **	Description of equity and other long-term award grant practices for employees and officers.
10(n) * **	Description of non-employee directors' compensation arrangements.
10(o) **	Form of restricted stock award that vests 20% per annum, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(k) of our Form 10-K for the year ended December 31, 2004).
10(p) **	Form of restricted stock award that vests on retirement, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(l) of our Form 10-K for the year ended December 31, 2004).
10(q) **	Form of restricted stock award that vests 20% per annum, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(m) of our Form 10-K for the year ended December 31, 2004).
10(r) **	Form of incentive stock option agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(n) of our Form 10-K for the year ended December 31, 2004).
10(s) **	Form of incentive stock option agreement that cliff vests 100% four years from the date of grant, for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(o) of our From 10-K for the year ended December 31, 2004).

EXHIBIT NO.	EXHIBIT
10(t) **	Form of non-qualified stock option agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(p) of our Form 10-K for the year ended December 31, 2004).
10(u) **	Form of non-qualified stock option agreement that cliff vests 100% four years from the date of grant, for grants to employees, officers and directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(q) of our Form 10-K for the year ended December 31, 2004).
10(v) * **	Form of stock appreciation rights agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus and Incentive Plan for Denbury Resources Inc.
10(w) * **	Form of stock appreciation rights agreement that vests 100% four years from the date of grant, for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(x) * **	Form of stock appreciation rights agreement that cliff vests 100% four years from the date of grant, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(y) * **	Form of restricted stock award that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus and Incentive Plan for Denbury Resources Inc.
10(z) * **	Form of restricted stock award that cliff vests 100% four years from the date of grant for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(aa) * **	Form of deferred payment cash award that vest 25% per annum, for grants to new employees and officers on their hire date.
10(bb) * **	Form of deferred payment cash award that cliff vests 100% four years from the date of grant for grants to employees and officers.
16	Letter from Deloitte & Touche LLP to the Securities and Exchange Commission dated May 24, 2004, regarding changes in certifying accountant, pursuant to Item 304(a)(3) of Regulation S-K (incorporated by reference as Exhibit 16.1 of our Form 8-K/A filed May 24, 2004).
21 *	List of subsidiaries of Denbury Resources Inc.
23(a) *	Consent of PricewaterhouseCoopers LLP.
23(b) *	Consent of Deloitte & Touche LLP.
23(c) *	Consent of DeGolyer and MacNaughton.
31(a) *	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b) *	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32 *	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99 *	The summary of DeGolyer and MacNaughton's Report as of December 31, 2005, on oil and gas reserves (SEC Case) dated February 2, 2006.

* Filed herewith.

** Compensation arrangements.

Copies of the above exhibits not contained herein are available to any security holder upon written request to the Secretary, Denbury Resources Inc., 5100 Tennyson Pkwy., Ste. 1200, Plano, Texas 75024.

Signatures

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

DENBURY RESOURCES INC.

/s/ Phil Rykhoek March 7, 2006
Phil Rykhoek
Sr. Vice President and Chief Financial Officer

/s/ Mark C. Allen March 7, 2006
Mark C. Allen
Vice President and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Denbury Resources Inc. and in the capacities and on the dates indicated.

/s/ Gareth Roberts March 7, 2006
Gareth Roberts
Director, President and Chief Executive Officer
(Principal Executive Officer)

/s/ Phil Rykhoek March 7, 2006
Phil Rykhoek
Sr. Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Mark C. Allen March 7, 2006
Mark C. Allen
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Ron Greene March 7, 2006
Ron Greene
Director

/s/ David I. Heather March 7, 2006
David I. Heather
Director

/s/ Randy Stein March 7, 2006
Randy Stein
Director

/s/ Wieland Wettstein March 7, 2006
Wieland Wettstein
Director

/s/ Greg McMichael March 7, 2006
Greg McMichael
Director

/s/ Donald Wolf March 7, 2006
Donald Wolf
Director

Exhibit 31(a)

Certification Under Section 302 of the Sarbanes-Oxley Act of 2002

I, Gareth Roberts, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Gareth Roberts March 7, 2006

Gareth Roberts
President and Chief Executive Officer

Exhibit 31(b)

Certification Under Section 302 of the Sarbanes-Oxley Act of 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Phil Rykhoek March 7, 2006

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2005 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission on March 7, 2006, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

/s/ Gareth Roberts March 7, 2006
Gareth Roberts
President and Chief Executive Officer

/s/ Phil Rykhoek March 7, 2006
Phil Rykhoek
Sr.Vice President and Chief Financial Officer

Corporate Information

BOARD OF DIRECTORS

Ronald G. Greene
Chairman of the Board
Principal
Tortuga Investment Corp.
Calgary Alberta

David I. Heather
Director
The Scotia Group
Dallas, Texas

Greg McMichael
Independent Consultant
Denver, Colorado

Gareth Roberts
President & C.E.O.
Denbury Resources Inc.
Dallas, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Wieland F. Wettstein
President
Finex Financial
Corporation, Ltd.
Calgary Alberta

Don Wolf
President & C.E.O.
Aspect Energy
Denver, Colorado

OFFICERS

Gareth Roberts
President & C.E.O

Tracy Evans
Senior Vice President
Reservoir Engineering

Phil Rykhoek
Senior Vice President &
Chief Financial Officer

Mark Worthey
Senior Vice President
Operations

Mark Allen
Vice President & Chief
Accounting Officer

Ron Gramling
Vice President
Marketing

Ray Dubuisson
Vice President
Land

Jim Sinclair
Vice President
Exploration

CORPORATE HEADQUARTERS

Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

REGISTER AND TRANSFER AGENT

American Stock Transfer
and Trust Company
New York, NY

LEGAL COUNSEL

Jenkens & Gilchrist

BANKERS

JP Morgan (Agent)

AUDITORS

PricewaterhouseCoopers LLP

EVALUATION ENGINEERS

DeGolyer & MacNaughton

STOCK EXCHANGE

New York Stock Exchange
Trading Symbol: DNR

Annual Meeting

The annual meeting of stockholders will be held on May 10, 2006, at 3:00 P.M., local time, at the Denbury offices located at:
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024

All stockholders are encouraged to attend, but if unable should complete and return the proxy card.

For Further Information

Contact Gareth Roberts or Phil Rykhoek at the Corporate Headquarters. We have listed on our website at www.denbury.com our corporate governance guidelines, as well as the charters for our nominating/governance committee, our compensation committee, and our audit committee. The website also contains other corporate governance information such as our code of ethics for our directors, officers and employees, our hotline number to report any abnormalities, and other data.

You may contact our board members by addressing a letter to:
Denbury Resources Inc.
Attn: Corporate Secretary, or by e-mail to secretary@denbury.com

Our Form 10-K filed with the SEC is included herein, excluding certain exhibits. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request to Laurie Burkes at the Company's headquarters. This report can also be accessed at our website, www.denbury.com. We have included herein our Section 302 and 404 certifications by the CEO and CFO of our Form 10-K filed with the SEC.

During 2005, the Company submitted its written affirmation and annual Chief Executive Officer certification for 2004 pursuant to Section 303A of the New York Stock Exchange regulations. Such certification was qualified as the Company failed to state in its May 2005 annual meeting proxy materials that its Chairman of the Board of Directors presides at the non-management director meetings. The Company will add this disclosure to its May 2006 proxy statement.

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BUILDING ON SOLID GROUND

DENBURY RESOURCES INC. 2005 ANNUAL REPORT